SO_2 EMISSION MONITORING PROTOCOLS

REVISED DRAFT REPORT

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CONTENTS

CONTENTS (continued)

TABLES

Page

TABLES (continued)

ACRONYMS AND ABBREVIATIONS

ADTP	air dried tons pulp
AMA	American Mining Association
AMS	Alternative Monitoring System
ASTM	American Society for Testing and Materials
CAM	Compliance Assurance Monitoring
CD	calibration drift
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CGA	Cylinder Gas Audit
CO	carbon monoxide
DAHS	Data Acquisition and Handling System
DAS	data acquisition system
EPA	U.S. Environmental Protection Agency
FCCU	fluid catalytic cracking units
GCV	gross calorific value
GCVTC	Grand Canyon Visibility Transport Commission
lbs/hr	pounds per hour
LME	Low Mass Emissions
LPG	liquified petroleum gas
MMBtu/hr	million British thermal units per hour
MTF	Market Trading Forum
MW	molecular weight
NO_x	oxides of nitrogen
NSPS	New Source Performance Standard
O_2	oxygen
OSI	Overall System Integrity
OTC	Ozone Transport Commission
Pechan	E.H. Pechan & Associates, Inc.
ppm	parts per million
PQA	Perrin Quarles Associates, Inc.
PSEL	plant site emission limit
QA	quality assurance
QC	quality control
RAA	Relative Accuracy Audit
RATA	Relative Accuracy Test Audit
RECLAIM	SCAQMD's Regional Clean Air Incentives Market
RM	Reference Methods
RTU	remote terminal unit
SCAQMD	South Coast Air Quality Management District
SIP	State Implementation Plan
SO_2	sulfur dioxide
SOP	standard operating procedure

ACRONYMS AND ABBREVIATIONS (continued)

SO_x	sulfur oxides
SRE	Sulfur Recovery Efficiency
SRU	Sulfur Recovery Unit
TBD	to be determined
TCI	Total Capital Investment
TIP	tribal implementation plan
TRS	total reduced sulfur
WRAP	Western Regional Air Partnership

FOREWORD

The Western Regional Air Partnership (WRAP) is a collaborative effort of tribal governments, State governments, and various Federal agencies to implement the recommendations of the Grand Canyon Visibility Transport Commission (GCVTC) and to develop the technical and policy tools needed by western States and tribes to comply with the U.S. Environmental Protection Agency (EPA) regional haze rule. The activities of the WRAP are conducted by a network of committees and forums composed of WRAP members and stakeholders who represent a wide range of viewpoints.

The WRAP established the Market Trading Forum (MTF), in large part, to develop and recommend emission control strategies for stationary sources of air pollution. A major focus of the MTF has been the establishment of regional emission milestones for sulfur dioxide (SO_2) and a regional backstop cap-and-trade program to be triggered if the milestones are not met through voluntary means.

Accurate emissions measurement is critical to the success of any cap-and-trade program. For many sources that would be subject to the cap-and-trade program (electric utility boilers are one example), SO_2 emissions are already well quantified and documented. Other sources may be using methods that are less accurate and/or less consistent across sources. The MTF established a emissions monitoring workgroup to address this issue.

This draft report is one of the products of the contractors [E.H. Pechan & Associates, Inc. and Perrin Quarles Associates, Inc. (Pechan and PQA)] that were hired to evaluate monitoring methods currently being used in the western States. This contractual effort is designed to develop emission monitoring protocols for non-electricity generating unit facilities, an estimate of their implementation cost, and regulatory text to facilitate their consistent codification among the WRAP members. The protocols would be implemented after the backstop trading program is triggered.

Note that the evaluations made in this report are performed without regard to the geographic locations of sources within the study area. Thus, sources located on tribal land are not handled any differently than those not on tribal lands. The evaluations consider the accuracy and cost of monitoring methods for similar sources. Similar sources are not just those within the same source type, but also can be classified based on fuel type or size as well.

The primary source categories identified by the workgroup for analysis include: copper smelters, refineries, natural gas processing plants, oil and gas production, lime plants, cement plants, industrial boilers (including cogenerators), aluminum smelters, and pulp and paper. An earlier MTF-sponsored floor allocation report identified the primary SO_2 emitting source types within these source categories. These are listed in Table 1. Because some of the SO_2 source types occur in more than one source category, the chapters in this report are organized by source type, rather than by source category, under the supposition that source types would have common monitoring methods. Where the analysis shows this not to be the case, emission monitoring protocols are identified separately based on the source category/source type combination. Table 1 provides a guide to which report chapters address each source category/source type combination.

Table 1
Association Among Primary Source Categories, Associated Source Types, and Report Chapters

Primary Source Category	Source Types	Report Chapter
1. Copper Smelters		II
2. Refineries		
	Sulfur Plants	III
	Fuel Combustion Unit - Boilers - Process Heaters	IV
	Catalytic Cracking Units	V
	Flares	VI
3. Natural Gas Processing Plants		
	Sulfur Plants	III
	Flares	VI
4. Oil and Gas Production		
	Sulfur Plants	III
	Flares	VI
5. Lime Plants		
	Kilns	VII
6. Cement Plants		
	Kilns	VIII
7. Industrial Boilers (including cogenerators)		
	Boilers - fossil-fuel fired	IV
8. Aluminum Smelters		
	Potlines	IX
9. Pulp and Paper		
	Boilers - fossil-fuel fired	IV
	Recovery Boilers	IV
	Lime Kilns	VII
10. Glass Manufacturing		
	Glass Melting Furnaces	X
	Boilers - fossil-fuel fired	X
11. Metallurgic Coke Production		
	Coke Calciners	XI
12. Sulfuric Acid Plants		
	Sulfuric Acid Production Plant	XII

PREFACE

A. REGULATORY FRAMEWORK FOR TRIBAL VISIBILITY IMPLEMENTATION PLANS

The regional haze rule explicitly recognizes the authority of tribes to implement the provisions of the rule, in accordance with principles of Federal Indian law, and as provided by the Clean Air Act §301(d) and the tribal authority rule [40 Code of Federal Regulations (CFR) §§49.1– .11]. Those provisions create the following framework:

1. Absent special circumstances, reservation lands are not subject to State jurisdiction.
2. Federally recognized tribes may apply for and receive delegation[1] of Federal authority to implement Clean Air Act programs, including visibility regulation, or "reasonably severable" elements of such programs (40 CFR §§49.3, 49.7). The mechanism for this delegation is a tribal implementation plan (TIP). A reasonably severable element is one that is not integrally related to program elements that are not included in the plan submittal, and is consistent with applicable statutory and regulatory requirements.
3. The regional haze rule expressly provides that tribal visibility programs are “not dependent on the strategies selected by the State or States in which the tribe is located” (64. Fed. Reg. 35756), and that the authority to implement §309 TIPs extends to all tribes within the GCVTC region (40 CFR §51.309(d)(12)).
4. EPA has indicated that under the tribal authority rule, tribes are not required to submit §309 TIPs by the end of 2003. Rather, they may choose to opt-in to §309 programs at a later date (67 Fed. Reg. 30439).
5. Where a tribe does not seek delegation through a TIP, EPA, as necessary and appropriate, will promulgate a Federal implementation plan within reasonable timeframes to protect air quality in Indian country (40 CFR §49.11). EPA is committed to consulting with tribes on a government-to-government basis in developing tribe-specific or generally applicable TIPs where necessary (See, e.g., 63 Fed. Reg. 7263-64).

The amount of modification, if any, needed for this report to fulfill tribal needs may vary considerably from tribe to tribe. The authors have striven to ensure that all references to tribes in the document are consistent with principles of tribal sovereignty and autonomy as reflected in the above framework. Any inconsistency with this framework is strictly inadvertent and not an attempt to impose requirements on tribes which are not present under existing law.

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[1]Tribes also possess a more fundamental source of authority to regulate their environments, based on their inherent authority as sovereign nations, which predates the formation of the United States. However, in the context of air pollution regulation and visibility planning in particular, tribal authority will more likely be based on delegation of Federal authority.

B. TRIBAL PARTICIPATION IN THE WRAP

Tribes, along with States and Federal agencies, are full partners in the WRAP, having equal representation on the WRAP Board as States. Whether Board members or not, it must be remembered that all tribes are governments, as distinguished from the "stakeholders" (private interest) which participate on Forums and Committees but are not eligible for the Board.

Despite this equality of representation on the Board, tribes are very differently situated than States. There are over four hundred Federally-recognized tribes in the WRAP region, including Alaska. The sheer number of tribes makes full participation impossible. Morever, many tribes are faced with pressing environmental, economic, and social issues, and do not have the resources to participate in an effort such as the WRAP, however important its goals may be. These factors necessarily limit the level of tribal input into and endorsement of WRAP products.

The tribal participants in the WRAP, including Board members Forum and Committee members and co-chairs, make their best effort to ensure that WRAP products are in the best interest of the tribes, the environment, and the public. One interest is to ensure that WRAP policies, as implemented by States and tribes, will not constrain the future options of tribes who are not involved in the WRAP. With these considerations and limitations in mind, the tribal participants have joined the State, Federal, and private stakeholder interests in approving this report as a consensus document.

CHAPTER I
SUMMARY OF FINDINGS AND RECOMMENDATIONS

A. IDENTIFICATION OF EXISTING BEST MONITORING PRACTICES

The initial phase of this project involved collecting information from State and Federal resources on monitoring practices at the primary industrial facilities that would be affected under a WRAP backstop trading program. We compiled information on Federal requirements in New Source Performance Standard (NSPS) subparts for the applicable source types, from recent Federal consent decrees that affect refineries, and from 40 CFR Part 75 requirements that affect industrial boilers that may opt in to the Acid Rain Program (or that are affected under the Oxides of Nitrogen (NO_x) State Implementation Plan (SIP) Call trading program). In addition, a number of State and local agencies were contacted based on a contact list provided by WRAP staff. Contacts were made with Arizona, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming, as well as the South Coast Air Quality Management District (SCAQMD) in California.

Based on this research, we compiled examples of monitoring approaches for each of the major industrial sector source types identified as possible trading sources. Table I-1 provides an overview of the State monitoring practices we identified for each source category. Table I-2 then provides the same information based on our review of applicable Federal NSPS requirements. Sections II through IX of this report provide more detailed information by source type.

B. DISCUSSION AND RECOMMENDATIONS/ISSUES FOR INDUSTRIAL SECTOR MONITORING PROTOCOLS

After compiling the various monitoring options, we evaluated the approaches and identified the best monitoring practices for each source category. These are summarized in Table I-3. The final column in the table indicates whether the monitoring is suitable for use as part of a trading program, whether a monitoring approach applied to a comparable source category should be considered for the trading program, or whether there are technical/cost issues that raise the possibility that other monitoring or applicability procedures should be considered to address the applicable source category/unit type.

In Table I-3, the Part 75 monitoring requirements are used as a primary benchmark in reviewing the best monitoring practices identified for each source category. EPA has developed Part 75 for the Acid Rain trading program, and has extended the use of Part 75 to other trading programs as well (such as the NO_x SIP Call). The Ozone Transport Commission used a monitoring program comparable to Part 75 for its regional NO_x trading

Table I-1
State Monitoring Methods Summary

Primary Source Category	Source Types	Arizona	SCAQMD Calif	Colorado	Idaho	Nevada	New Mexico	Oregon	Utah	Wyoming
1. Copper Smelters		SO_2 Continuous Emissions Monitoring System (CEMS) for stacks with specific limits. Also, facility-wide monthly material balance.					SO_2 CEMS and sulfur balance.		SO_2 CEMS	
2. Refineries	Sulfur Plants (SRU)		SO_2 monitor at the outlet of the tail gas unit plus incinerator. Flow CEMS.				CEMS for flow and SO_2. Also requires daily measurement of incinerator temperature, incinerator excess oxygen (O_2), acid gas flow rate, H_2S conc. and accumulated elemental sulfur recovered.		SO_2 CEMS (no flow requirements)	SO_2 CEMS operated according to 40 CFR 60, Appendix F.
	Fuel Gas Combustion Unit - Boilers - Process Heaters		Fuel gas continuous monitoring(or use SO_2 CEMS on a representative stack and back calculate sulfur content in the mix drum). Also, fuel flow monitoring to calculate mass emissions.				Fuel gas H_2S monitoring and fuel usage is required for sources subject to Subpart J. CEMS may be required for NO_x and carbon monoxide (CO) based on size of unit. No SO_2 CEMS required for firing nat. gas.			Monitor fuel oil and fuel gas usage. Sample fuel oil for sulfur content. Monitor fuel gas H_2S content.

Table I-1 (continued)

Primary Source Category	Source Types	Arizona	SCAQMD Calif	Colorado	Idaho	Nevada	New Mexico	Oregon	Utah	Wyoming
	Catalytic Cracking Units		SO_2 and Flow CEMS				CEMS is proposed in a consent decree [requirements are to be determined (TBD)]		SO_2 CEMS (no flow requirements)	SO_2 CEMS
	Flares		Not considered by SCAQMD's Regional Clean Air Incentives Market (RECLAIM). Rule 1118 addresses. They do episodic sampling.				Measure acid gas flow and concentration and fuel gas flow for supplemental heat. Calculate acid gas flared.			No monitoring required.
3. Natural Gas Processing Plants	Sulfur Plants						Same as refinery sulfur plant		SO_2 CEMS (no flow requirements)	
	Flares						Analyzer to measure and record flow and H_2S of both inlet gas to plant and acid gas to flare.			
4. Oil and Gas Production	Sulfur Plants									
	Flares									
5. Lime Plants	Kilns	No requirements to monitor or regulate SO_2.			See below under 9. Pulp and Paper -- Lime Kilns.	Daily coal sulfur analyses, daily production records, stack emission testing once every five years.		CEMS for TRS	Stack test every 5 years.	

Table I-1 (continued)

Primary Source Category	Source Types	Arizona	SCAQMD Calif	Colorado	Idaho	Nevada	New Mexico	Oregon	Utah	Wyoming
6. Cement Plants	Kilns	Annual performance test	SO_2 and Flow CEMS (kiln with standard baghouse and stack). SO_2 and parametric flow correlation (kiln with positive pressure baghouse without a stack where no suitable location for flow CEMS).	SO_2 and Flow CEMS at Holcim-Florence Plant		Kiln 1 total annual throughput and fuel use. Kiln 2 monthly coal sulfur analyses, annual production records, stack test once per year		Kiln source test once per permit term. Monitor sulfur content of each fuel shipment.	Stack test every 2 years plus fuel sulfur content	
7. Industrial Boilers (including cogenerators)	Boilers - fossil-fuel fired - coal, solid fuel - natural gas - process gas - fuel oil	*[Not investigated with States in detail because of existing monitoring practices applicable to this source type under Part 75 and NSPS]*								
8. Aluminum Smelters	Potlines							Source test semi-annually for SO_2		
9. Pulp and Paper	Recovery Boilers							SO_2 CEMS with stack flow based on BLS monitoring and BLS/stack flow correlation		
	Lime Kilns				SO_2 CEMS with stack flow based on parameter monitoring correlation.			TRS CEMS		
10. Glass Manufacturing	Glass Melting Furnaces		SO_2 CEMS and in-stack flow meters	SO_2 CEMS and monitoring of fuel consumption				Fuel sulfur content measurements and production records used to estimate SO_2 emissions		

Table I-1 (continued)

Primary Source Category	Source Types	Arizona	SCAQMD Calif	Colorado	Idaho	Nevada	New Mexico	Oregon	Utah	Wyoming
11. Metallurgic Coke Production	Coke Calciner		SO_2 and flow CEMS							Stack test to establish SO_2 emission factor. Measure annual production.

Table I-2
NSPS/Other Federal Monitoring Methods Summary

Primary Source Category	Source Types	Applicable NSPS	SO_2/Flow Monitoring Requirements
1. Copper Smelters	Roasters, Smelting furnace, Copper converters	Subpart P	SO_2 CEMS (no flow measurements)
2. Refineries	Sulfur Plants (SRU)	Subpart J	SO_2 CEMS (no flow measurements). If no incineration after recovery, can measure as TRS rather than as SO_2
	Fuel Gas Combustion Unit -Boilers -Process Heaters		H_2S continuous monitoring (can be at common drum serving multiple units) or SO_2 CEMS (no flow measurements under either option)
	Catalytic Cracking Units		SO_2 CEMS (no flow measurements). CEMS not required for units without add-on control device to meet NSPS limits.
	Flares	Consent Decrees	Flowmeters, H_2S concentration (from sulfur recovery analyzer, knowledge of sulfur content, or direct (periodic) measurement), and use of applicable formula to convert to SO_2 tons.
3. Natural Gas Processing Plants	Sulfur Plants	Subpart LLL	Daily measurements of sulfur product accumulation, H_2S concentration in acid gas, and average flow rate (based on continuous measurements). Also, SO_2 CEMS and temperature monitoring for incinerator controlled units, expressed as mass per unit of time. If no incinerator (or in place of temperature monitor), TRS CEMS, but expressed as SO_2 mass per unit of time.
	Flares		None
4. Oil and Gas Production	Sulfur Plants	No NSPS	Not applicable
	Flares		Not applicable
5. Lime Plants	Kilns	Subpart HH	None
6. Cement Plants	Kilns	Subpart F	None

Table I-2 (continued)

Primary Source Category	Source Types	Applicable NSPS	SO_2/Flow Monitoring Requirements
7. Industrial Boilers (including cogenerators)	Boilers - fossil-fuel fired - coal, solid fuel - natural gas - process gas - fuel oil	(a) Part 75 (b) Subparts D, Db, Dc	(a) For boilers >250 million British thermal units per hour (MMBtu/hr), Part 75 requirements (SO_2/Flow CEMS if solid fuel, fuel flow and fuel sampling option if oil or gas-fired) (b) For boilers 30-250 MMBtu/hr, SO_2 CEMS (no flow measurements). Also, daily fuel sampling or daily reference method testing options in certain circumstances. Fuel supplier certification also an option for low sulfur oil.
8. Aluminum Smelters	Potlines	Subpart S	None
9. Pulp and Paper	Boilers - fossil-fuel fired	Subparts D, Db, Dc	See Item 7., above
	Recovery Boilers		TRS CEMS (no flow measurements)
	Lime Kilns		TRS CEMS (no flow measurements)
10. Glass Manufacturing Plants	Glass Melting Furnace	Subpart CC	No SO_2 limits or monitoring requirements
11. Metallurgic Coke Production	Coke Calciner	No NSPS	Not applicable
12. Sulfuric Acid Plants	Sulfuric Acid Production Unit	Subpart H	SO_2 CEMS (no flow measurements)

Table I-3
Current Best Monitoring Practices Summary

Source Type	Monitoring Method	Where Required	Trading Recommendations/Issues
1. Copper Smelters	(a) Material Balance [American Mining Association (AMA) Proposal] (b) SO_2/Flow CEMS [Kennecott, main stack]	(a) AMA proposal based on AZ and NM requirements (b) Utah	(a) AMA proposal is to be discussed by States, EPA, and industry (b) Utah protocol is Part 75 comparable; require Part 75 compliance
2. Sulfur Plants	SO_2/Flow CEMS	Utah and South Coast, CA	Part 75 comparable; require Part 75 compliance
3. Refinery Fuel Combustion Units	(a) Fuel gas continuous monitoring for fuel sulfur content and flow based on fuel flow meters. (b) Alternate Option: Also may use SO_2 CEMS on a representative stack to back calculate sulfur content in fuel in lieu of fuel gas continuous monitoring.	South Coast, CA	(a) Part 75 comparable; require Part 75 compliance (b) Consider adding this approach as optional protocol
4. Catalytic Cracking Units	SO_2/Flow CEMS	South Coast, CA (SO_2 CEMS also in NSPS, Utah and consent decree proposal for New Mexico refinery)	Part 75 comparable; require Part 75 compliance
5. Flares	Flowmeters, H_2S concentration (from sulfur recovery analyzer, knowledge of sulfur content, or direct (periodic) measurement), and use of applicable formula to convert to SO_2 tons	Refinery consent decrees	Limited usefulness for trading program -- see discussion.
6. Lime Kilns	SO_2 CEMS with stack flow based on parameter monitoring correlation.	Idaho (lime kiln at a pulp and paper facility)	(a) Consider use of flow CEMS as applied currently for cement kilns (b) Positive pressure baghouse exception may be necessary (see cement kilns)

Table I-3 (continued)

Source Type	Monitoring Method	Where Required	Trading Recommendations/Issues
7. Cement Kilns	(a) SO_2/Flow CEMS (b) Exception: Use correlation approach for flow if positive pressure baghouse prevents use of a flow CEMS	Colorado and South Coast, CA	(a) Part 75 comparable; require Part 75 compliance (b) Exception technically necessary -- add as optional protocol for positive pressure baghouse application
8. Aluminum Smelters	Source test semi-annually for SO_2, together with sulfur sampling of anode materials to show compliance with plant mass emission limit	Oregon	Existing best monitoring practices inadequate for trading. Presence of both significant fugitives and controls for captured emissions would require materials balance approach plus inlet/outlet SO_2 control device CEMS and flow CEMS to account for controlled emissions. Consider addressing aluminum smelters outside of trading program.
9. Gas or Oil-Fired Boilers	1) SO_2/Flow CEMS, or 2) Fuel sampling and fuel flowmeters, or 3) If emit <25 tons/year SO_2, use default SO_2 value plus default heat input (or long term fuel flow method for heat input)	Part 75; South Coast, CA	Part 75 applies; require Part 75 compliance
10. Solid- Fuel Fired Industrial Boilers >250 MMBtu/hr	SO_2/Flow CEMS	Part 75 (opt-in units)	Part 75 applies; require Part 75 compliance

Table I-3 (continued)

Source Type	Monitoring Method	Where Required	Trading Recommendations/Issues
11. Solid- Fuel Fired Industrial Boilers <250 MMBtu/hr	SO_2 CEMS, or daily stack test, or coal sampling and analysis. No flow monitoring required under NSPS	NSPS	Based on NSPS, SO_2 CEMS appear applicable from technical and economic standpoint. At some point, size may be an issue from economic standpoint; could consider applicability cutoff, although WRAP floor allocation inventory suggests cutoff for small, solid-fuel-fired boilers may be unnecessary. Given SO_2 CEMS requirements, lack of flow monitoring appears to be based on lack of regulatory need as opposed to technical/cost considerations.
12. Recovery Furnaces	SO_2 CEMS and fuel monitoring correlation method for flow	Current Practice - Oregon	Consider adding flow CEMS given application to comparable industrial boiler and kiln applications.
13. Glass Melting Furnaces	SO_2 CEMS and in-stack flow meter, or an alternate method for low flow rates	South Coast, CA	Part 75 comparable; require Part 75 compliance
14. Coke Calciners	SO_2 and flow CEMS	South Coast, CA	Part 75 comparable; require Part 75 compliance
15. Sulfuric Acid Plants	SO_2/flow CEMS	Utah and Arizona	Part 75 comparable; require Part 75 compliance

program as well. The SCAQMD likewise adopted generally similar approaches for all major sources (generally those with over 10 tons of SO_2 emissions per year for the relevant source types) as part of its SO_2 RECLAIM program.

For solid fuel units, Part 75 requires an SO_2 and flow CEMS to determine SO_2 mass emissions. However, it is important to note that Part 75 (and the Ozone Transport Commission (OTC) and RECLAIM programs) do include some non-CEMS options for other units. For gas and oil fired units, Part 75 allows the use of fuel flow monitoring and fuel sampling (with sampling frequencies based on sulfur content and variability). For gas and oil units that have low mass emissions ($\leq$25 tons per year), Part 75 allows the use of default values to account for mass emissions. The RECLAIM program has similar fuel-based options.

Part 75 has not been applied to all forms of industrial facilities, and our use of Part 75 as a benchmark does not exclude consideration of options, which may not meet the same criteria as Part 75. Rather, for those source categories where the best monitoring practices are comparable to the Part 75 benchmark, we note that further, detailed technical justification and consideration of monitoring alternatives for that source category is generally unnecessary, except for considering alternative technical exceptions. For instance, the best monitoring practices for industrial boilers and cogenerators are generally comparable to Part 75 requirements. Also, in a number of non-boiler/process heater source categories, State or local requirements were found which are comparable to Part 75 SO_2 and Flow CEMS. These include refinery sulfur plants and catalytic cracking units, and Portland cement kilns required to use SO_2 and flow CEMS.

For categories where the current best monitoring practices do not compare favorably with the Part 75 benchmark, further analysis is required to identify the technical, economic, or regulatory reasons for the current level of monitoring, and, based on those factors, establish recommendations for appropriate monitoring protocols. The following discussion amplifies the findings listed in Table I-3 for each of the primary source types.

(1) Industrial Boilers and Cogenerators

Part 75 monitoring requirements are directly applicable to the fossil fuel fired industrial boiler and cogenerator category. Therefore Part 75 monitoring methods are identified generally as the best monitoring practice for these units.

However, consideration must be given to the appropriateness of Part 75 as a best monitoring practice for smaller units. Part 75 requirements currently apply to units serving generators with a nameplate capacity greater than 25 MW. This is comparable to a unit with 250 million Btu/hr rated heat input capacity (10,000 Btu/kilowatt hour heat rate). A number of the coal-fired industrial boiler units in the floor allocation inventory are smaller than this threshold, so we do not identify Part 75 as the current best monitoring practice for these units. Instead, the Part 60 NSPS practices are identified as best monitoring practice for units >30 MMBtu/hr capacity but <250 MMBtu/hr capacity. These requirements typically require an SO_2 CEMS, although the NSPS allow for daily stack testing or coal sampling and analysis as an option. The NSPS does not impose any flow monitoring because flow data are unnecessary to establish compliance with the NSPS limits. However, at least one State has applied parametric correlation methods for flow to the industrial boiler category, so we list that technique as the best flow monitoring practice for this group of units.

Recommendation: Require compliance with Part 75.

(2) Recovery Furnaces

The current best monitoring practices (State and Federal) identified for paper mill recovery furnaces are not comparable to Part 75. The NSPS do not require SO_2 or flow monitoring. While we identified State requirements to use a CEMS for SO_2, we did not identify any stack flow CEMS requirements. We did identify a State requirement to determine stack flow based on a correlation with black liquor flow monitoring. The technical monitoring application of a flow CEMS, however, should be the same for a recovery furnace as a fossil fuel-fired boiler. Thus, the lack of a State requirement for a flow CEMS appears to be based on the lack of a regulatory driver for such a requirement, as opposed to technical aspects of flow monitoring. Given the size of a typical recovery furnace and total plant investment for pulp mills (and existing SO_2 CEMS), the cost implications of adding a flow CEMS do not appear unreasonable compared to flow CEMS applied to other industrial sectors. Thus, there does not appear to be a strong rationale for using a non-CEMS approach to flow monitoring for this source category that differs from the recommendation for the industrial boiler category.

Recommendation: Require compliance with Part 75.

(3) Refinery Combustion Sources

The NSPS, SCAQMD RECLAIM, and Part 75 all establish the option for monitoring sulfur content of the fuel as a method for determining SO_2 emissions. The RECLAIM and Part 75 rules also apply fuel flow metering to determine SO_2 mass emissions. Thus, the existing best monitoring practices for these units are appropriate for use in a trading program.

Recommendation: Require compliance with Part 75; consider RECLAIM monitoring as an option.

(4) Cement and Lime Kilns

Existing State monitoring practices already include an SO_2 and Flow CEMS requirement for a cement kiln. The best monitoring practice identified for a lime kiln was a State requirement for an SO_2 CEMS, with flow determined using parameter monitoring correlations. Given the application of a flow CEMS to the generally comparable cement kiln application, this difference in best monitoring practices appears to be driven by general regulatory considerations and not significant technical issues. Given the similarity between the two types of kilns, and the existing application of one type of CEMS to a lime kiln, the general recommended approach for the kiln applications is an SO_2/Flow CEMS approach.

However, a flow CEMS may not be appropriate for cement or lime kilns served by positive pressure baghouses. The lack of a location for a flow CEMS downstream of the control device (to avoid interference from the harsh, upstream environment), is a technical obstacle to use of a flow CEMS in these situations. In those cases the best monitoring practice for flow is a parameter monitoring correlation (identified for a cement kiln in the South Coast RECLAIM program).

Recommendation: Require compliance with Part 75; use RECLAIM approach for flow monitoring at units with positive pressure baghouses. See also consideration of "opt out" provisions for units in this source category as part of considering monitoring costs.

(5) Sulfur Plants and Fluid Catalytic Cracking Units (FCCUs)

For sulfur plants, the proposed monitoring protocol requires SO_2 and flow rate CEMS. Such requirements are already in place in Utah and the South Coast of California. While the floor allocation method sets the floor for each unit using a lower emission factor for the larger sulfur plants than it does for smaller units (using the same criteria as the NSPS), there appear to be no barriers to applying the same monitoring requirements to all sulfur plants regardless of size. All sulfur plants at refineries are included in the trading program, for example.

As with sulfur plants, the proposed monitoring protocol for FCCUs at refineries requires SO_2 and flow CEMS. Because there may be flow monitoring concerns for refineries that do not have CO boilers, we are investigating whether there are any western State refineries with FCCUs that do not also have CO boilers. If all FCCUs have CO boilers, a single protocol should be sufficient for this source type. The evaluation performed so far has used the 1996 WRAP point source file and the 1999 National Emission Inventory to check whether there are CO boilers at western State refineries. Very few CO boilers show up in these data sets. Therefore, we will probably have to rely on industry contacts for this information.

The SCAQMD does have specialized procedures for conducting quality assurance (QA) on CEMS for units with low SO_2 concentrations. Part 75 also has special procedures for quality assurance tests for units with low concentrations. A further detailed analysis of the differences in these procedures will be conducted to evaluate whether one, or both, of the approaches should be used for purposes of this trading program.

Recommendation: Require compliance with Part 75 for both sulfur plants and FCCUs. For an FCCU without a CO boiler, consider flow monitoring alternatives if necessary based on stack configuration issues. Also, compare SCAQMD spiking protocol for quality assurance purposes compared with Part 75 approaches (for units with low SO_2 concentrations).

(6) Glass Melting Furnaces

SO_2 monitoring requirements were evaluated for glass manufacturing plants in Colorado, Oregon, and the SCAQMD. The plants in Colorado and Oregon emitted all SO_2 via a stack. Colorado requires continuous monitoring systems for SO_2 and monitoring of fuel consumption, while Oregon estimates SO_2 emissions from monthly production records for tons of glass melted, and natural gas and fuel oil fuel usage estimates from meter/gauge readings. SO_2 emissions are then calculated using emission factors.

The SCAQMD requires the use of CEMS at the glass plant(s). There are some flow monitoring issues at these plants because oxy-fuel systems are being adopted (using oxygen rather than air). Oxygen use reduces the overall flow as there is reduced oxidizer volume. In these cases, they cannot use an alternate method such as measurement of the fuel burned and use of an f-factor to determine stack flow. In-stack flow meters must be used or an alternative method for low flow rates such as the use a tracer gas (e.g., helium).

Recommendation: Require compliance with Part 75. For low flow situations, we do not recommend a separate protocol at this time. Given the small number of affected plants, a petition for an alternative for any such situation that may arise appears to be an acceptable approach to address site-specific issues.

(7) Metallurgic Coke Production

There are limited coke production operations in the WRAP Region. Protocols for this industry are based on the rotary calciner used for coke production at P4 Production in Rock Springs, Wyoming and facilities operating in the South Coast of California. No SO_2 emission monitoring is required for the Wyoming facility. Annual SO_2 emissions are computed using a stack test-based SO_2 emission factor and operating hours/production rate estimates.

There is at least one coke calciner included in the South Coast RECLAIM program, and the CEMS and flow monitoring requirements are no different from those applied under SCAQMD Rule 2011 for other source types, so the SO_2 emission monitoring protocol for metallurgic coke production is based on these South Coast requirements.

Recommendation: Require compliance with Part 75.

(8) Sulfuric Acid Production Plants

Emission monitoring protocols for sulfuric acid plants are based on the requirements for acid plants at copper smelters in the region. Because SO_2 CEMS and flow monitoring are required for the Kennecott unit, these are considered the best monitoring practices for H_2SO_4 production.

Recommendation: Require compliance with Part 75.

(9) Sources with Fugitive Emissions

There are a number of categories with significant fugitive SO_2 emissions for which Part 75 methods are not appropriate. These include the two primary smelter categories (aluminum and copper), and refinery flares. For the smelters, some combination of mass balance including SO_2 and flow CEMS, may be required based on the specific smelter. Flares have intermittent emissions, with a large range in concentrations.

(a) Copper Smelters

For copper smelters in the transport region, there need to be two monitoring protocols. The first is based on the current requirements for Kennecott-Salt Lake, which underwent a modernization effort during the mid-1990s, and emits all of its SO_2 via stack releases. The emission monitoring requirements for Kennecott are to install and monitor SO_2 and flow via a CEM at the acid plant and the main smelter stack. A separate protocol is needed for smelter configurations that currently exist in Arizona and New Mexico, where a large fraction of the SO_2 emissions are vented to the atmosphere as fugitives. This protocol is based on the Arizona Mining Association proposal, which in turn is based on current SIP-approved monthly material balance requirements.

Recommendation: For any plant such as the Kennecott plant, require compliance with Part 75. For smelters with fugitive emission sources, no protocol can be recommended at this time given the significant emissions from this sector, and the differences in data precision, accuracy, frequency, and overall quality between the mass balance option for these smelters and the monitoring available for other sources. EPA, the States, and the industry are expected to continue discussions on the appropriate protocol for these sources. As an interim measure, consider one of the non-monitoring options in subsection (d) below.

(b) Aluminum Smelters

Recent information provided by the Oregon Department of Environmental Quality indicates that Reynolds Metals has closed permanently and the primary smelter at the Northwest Aluminum plant is temporarily shut down. Current monitoring requirements for aluminum smelters in Oregon are limited to a semi-annual source test for SO_2 together with sulfur sampling of anode materials to show compliance with a plant mass emission limit. Average annual SO_2 emissions at this plant are about 400 tons. If the best current practice is used to define the emission monitoring protocol for aluminum smelters, then the requirements for this category would be well below those for those for the other categories being studied. While not specifically demonstrated for this source type, the stack SO_2 emissions from an aluminum smelter should be amenable to SO_2 CEM and flow measurement. However, it has not been determined what fraction of the SO_2 emissions are stack versus fugitive emissions. The 1996 WRAP point source data base shows that 55 percent of the facility-level SO_2 comes from the vertical stud soderberg cell. This may indicate that the remaining 45 percent of the SO_2 is released from vents, etc.

Therefore, if this plant was to be included in the trading program, the protocol would have to address both stack and fugitive emissions from this facility. One approach would be to account for all sulfur inputs (similar to the copper smelter protocol), use inlet/outlet SO_2 CEMS plus flow monitoring to account for the sulfur controlled at the stack, and then assume the remaining sulfur is emitted as SO_2. Given the potential complexity of this option, and recent information that the only remaining smelter may be curtailing operations, the WRAP may want to consider excluding this source category from the program, or establishing a generic petition process within the rule to add a source-specific protocol if needed for this type of facility. See subsection (d), below, for further discussion.

Recommendation: Consider one of the non-monitoring options in subsection (d), below.

(c) Flares

The best monitoring practice was from a recent consent decree that required gas flow monitoring combined with periodic sampling/analysis for sulfur content. Potential bypass of flares is an issue for monitoring under a trading program, however. Note that the SCAQMD excluded flares from their RECLAIM program. Because of the nature of this emission source, exclusion from the trading program or providing flares with non-tradeable allowances may be an option (see below).

Recommendation: Consider one of the non-monitoring options in subsection (d), below.

(d) Other Non-monitoring Options for Fugitive Sources

Because of the inherent difficulty of monitoring sources with significant fugitive emissions, especially in a manner comparable to the other participants in the trading program, the WRAP may want to consider the option of excluding these units from the trading program. The volume of the emissions from the copper smelter sector (and also from flares) may make this option unacceptable. The volume from aluminum smelters should not affect the overall viability of the trading program.

A second alternative is to include these categories in the trading budget and allocate allowances, but not allow these source types to sell allowances. The sources would use the best available monitoring to account for their emissions and balance the total emissions against their allowances. If emissions are less than allowances, then the sources would require no further action. If emissions exceeded allowances, then the sources would have to buy sufficient allowances to cover their emissions. Because this issue is a fundamental trading program design issue and not an emissions monitoring issue, we have not evaluated this option fully as part of this report.

A third option would be to establish a generic petition process in the current trading rule that would enable a separate approval process for these types of complex monitoring situations, which often may have source-specific issues that limit the usefulness of a generic protocol. The petition could require the source to develop a proposed protocol (which may be based on a protocol already approved under the SIP for other non-trading program purposes), then approval by the applicable State, and subsequent approval into the SIP by EPA before the source may participate in the trading program. This approach would enable the States to proceed with current SIP rulemakings on the essential elements of their section 309 plans. The States then could work with the relatively few sources involved and with EPA on the technical monitoring details for these sources. This approach seems necessary if these sources are to be included given that the current monitoring approaches do not readily translate into emissions accounting with the same degree of accuracy as methods that would be employed by other sources participating in the trading program.

C. COST ISSUES

In evaluating the costs of monitoring options, we identified the following primary sources of information:

(1) ***Part 75 Cost Study and ICR***. EPA's Clean Air Markets Division had collected information from vendors and other sources on CEMS, fuel flowmeter, and testing costs as part of evaluating the costs of its monitoring requirements under the Acid Rain Program and NO_x SIP Call. Based on that information, we have included information that indicates that the annualized cost of an SO_2/Flow CEMS to meet Part 75 requirements will be approximately $75,000 (1998 dollars). For a fuel flowmeter, the total capital costs were estimated at $3,000-8,000 approximately for gas or oil meters (excludes installation costs), with quality assurance cost of up to $2,000 per year. Fuel sampling costs would be an additional expense, but those values were not part of this study (the ICR for Part 75 does assume approximately $300/oil sample for oil-fired units, while gas-fired units rely on fuel supplier information or default values).

(2) ***OAQPS CEM Cost Model***. EPA's Office of Air Quality Planning and Standards developed a CEM Cost Model for meeting Part 60 (NSPS) requirements. Based on that model (in 1998 dollars) the annualized cost of an SO_2/Flow CEMS would be approximately $58,000.

Additional cost information was not identified in an initial search. For purposes of this initial report, we did not attempt to gather further details or contact vendors directly to assemble additional data. To the extent the WRAP participants identify particular monitoring applications where additional cost data would enhance the final decision making process on acceptable monitoring protocols, we will contact appropriate vendors and affected facilities to evaluate costs in detail for that application.

Two other factors should be considered in evaluating the cost implications of monitoring options for the WRAP trading program:

- The program applies to all SO_2 emitting units at a facility, regardless of size or the amount of emissions, and
- The program does not establish emission reduction targets for a number of the source categories that will participate in the program.

The first consideration – presence of small units – suggests that the rule may require some form of reduced monitoring or opt out process for these small units. As an example, a smelt dissolving tank at a kraft pulp mill may have a small amount of SO_2 emissions that would be prohibitively expensive to monitor with the same reliability, accuracy and precision as the recovery boiler at the same facility. An emergency diesel generator at a facility would be another possible example. The best monitoring practices identified in this report focused on the primary emissions units at facilities such as a pulp mill, and do not take into account these minor points of SO_2 emissions.

The second consideration – facilities with no reduction targets – also suggests the possibility of an opt out process. These facilities, if they do not intend to control emissions and create tradeable allowances, would be required to employ significant, and costly, monitoring only for tracking emissions at historical levels if required to participate fully in the trading program.

An alternative would be to account for the emissions from these units as part of the overall trading budget, but then allocate the allowances as non-tradeable allowances. If the source continues to operate at or below historical operating levels, the source can continue to use the same emission estimation procedures used to allocate emissions, and thereby have sufficient allocated allowances to cover all of the emissions. If operations increase, the facility would have to purchase additional allowances to cover its estimated increased emissions, based on the same emission estimation techniques used to establish the allowance allocation for the source. If the source intended to expand operations significantly, or adopt control measures to have allowances for trade, the source could choose not to opt out but instead comply fully with the monitoring requirements for trading sources and receive tradeable allowances.

This type of approach would limit the cost of the trading program for those facilities that are not expected or required to be active participants in reducing or trading emissions. However, the impact of this *opt out* option in the context of the overall allowance allocations under the trading program could affect a significant portion of the overall non-utility sector emissions. Table I-4 reproduces Table XIV-1 from the "Market Trading Forum Non-utility Sector Allocation: Final Report from the Allocations Working Group," which lists the total floor allocations for the various industrial categories (WGA, 2002). The categories that could be eligible for this opt out provision include cement and lime manufacturing, pulp and paper process units (including recovery boilers and lime kilns, but not other boilers), elemental phosphorous production, glass manufacturing, and metallurgical coke production. In evaluating the total potential impact of this type of opt out provision, the relative contribution of the industrial sector versus the utility sector to total regionwide emissions needs to be considered. The electric generating sector comprises over 50 percent of the total 2018 milestone emissions from sources that would be included in the trading program, and this opt out provision would not apply to any of those electric generating units.

Table I-4
State/Sector Summary of SO_2 Floor Allocations
(tons per year)

States	Sectors												Total
	Refineries	Lime Manufacturing*	Industrial Boilers	Pulp and Paper	Cement Manufacturing	Natural Gas Processing	Elemental Phosphorus**	Glass Manufacturing***	Copper Smelters	Aluminum Plants	Sulfuric Acid Plants	Coke Production	
Arizona		1,365	978		320				43,000				45,663
California****													27,335
Colorado	1,614		387		4,936			237					7,174
Idaho			601	1,807	522		15,861				2,551		21,342
Nevada		435			448								883
New Mexico	2,244				1,103	12,862			34,000				50,209
Oregon			1,585	5,377				131		2,076			9,169
Utah	4,142	303	2,010		267	1,593			1,000				9,315
Wyoming	3,418		2,350		165	14,429					2,835	631	23,828
Total	**11,418**	**2,103**	**7,911**	**7,184**	**7,761**	**28,884**	**15,861**	**368**	**78,000**	**2,076**	**5,386**	**631**	**194,918**

NOTES: *Based on 1998 and 2000 historical SO_2 emission estimates.
**Based on year 2000 SO_2 emission estimates for P4 Production, which are substantially higher than 1996 or 1998 emissions.
***Based on 1996, 1998, and 2000 historical SO_2 emission estimates.
****Sector-level emissions are not reported for California – just the State total.

CHAPTER II
COPPER SMELTERS

Primary copper smelters process copper sulfide ore concentrate to produce anode copper. Most of the smelters use a batch copper converting process (either Pierce-Smith or Hoboken converter designs) to produce blister copper. The Kennecott Utah Copper Corporation (Kennecott) smelter, however, uses a flash copper converting technology, which produces blister copper in a continuous process. All primary copper smelters in the WRAP region control SO_2 emissions by routing the process off-gases from the smelting and converting processes to double contact sulfuric acid plants. Fugitive SO_2 emissions result from equipment leaks and from slag tapping, matte tapping, and slag return. Fugitive emissions are sometimes captured with a hood and routed to air pollution control equipment.

There are six primary copper smelters in the WRAP region. Currently, only three of these smelters are producing copper; the ASARCO smelter in Hayden, Arizona, the Phelps Dodge smelter in Miami, Arizona, and Kennecott near Garfield, Utah. The other three smelters have suspended operations and are not producing copper at this time. Pechan reviewed permit information for three copper smelters; BHP in San Manuel, Arizona, ASARCO, and Kennecott. Note that the monitoring requirements for fuel combustion units at smelters were not reviewed since these requirements are discussed in a separate chapter in this report.

As stated above, Kennecott utilizes a different copper smelting process than the smelters in Arizona and New Mexico. The majority of the SO_2 emissions generated from this process are released at the main stack. Therefore, Utah requires the main stack at Kennecott to have a CEMS for SO_2 and NO_x, flow monitoring, and stack testing every 3 years. Kennecott is required to have an SO_2 CEMS for the sulfuric acid plant (40 CFR 60 Subpart H, NSPS for Sulfuric Acid Production). It is also required to monitor other emissions units at the plant as well. The wet scrubbers are required to be monitored for pressure drop and liquid flow to the scrubbers. Periodic stack testing for SO_2 and sulfuric acid is required at the following emissions units: liberator, cathode washing, anode scrap washing, precious metals recovery, silver production. The monitoring requirements for Kennecott are summarized in Tables II-1 and II-2.

The process used by smelters in New Mexico and Arizona results in significant SO_2 being emitted as fugitive emissions. A different monitoring scheme is required for these smelters. The AMA submitted recommendations for SO_2 emissions monitoring at copper smelters in New Mexico and Arizona. The recommendation is presented in Attachment A at the end of this chapter. The AMA proposed a sulfur balance method for the facility which requires sampling of all sulfur containing materials and calculating the sulfur removed by processes and air pollution control equipment. There are no requirements for SO_2 CEMS. The proposal does not throughly address missing data. In addition, for quality assurance requirements, the ASARCO permit contains a quality assurance/quality control

(QA/QC) plan for sulfur analysis at its laboratory that could supplement the AMA proposal (see Attachment B).

Arizona requires measurement systems for continuously monitoring SO_2 concentrations and stack gas volumetric flow rates of the following emissions sources: (1) outlet of each piece of SO_2 control equipment, (2) captured fugitive emissions (hoods), and (3) converter roof fugitive emissions. Arizona also requires SO_2 CEMS and flow monitoring for the acid plant tail gas. Lastly, Arizona requires that any bypass to the acid plant be equipped to monitor and record all periods that the bypass is in operation. The monitoring requirements for Arizona are summarized in Tables II-3 and II-4. These monitoring requirements assess compliance with specific emission limits, and would not provide a full accounting of all emissions at a typical smelter.

Ambient SO_2 monitoring in the vicinity of the smelter site is required for ASARCO and Kennecott. The Kennecott permit does not require continuous recording of the monitor if it is equipped with an alarm. Ambient air monitoring requirements are not summarized in this chapter.

Table II-1
Monitoring Requirements for Main Stack and Other SO_2 Sources at Kennecott Copper in Utah

Primary Source Category: Copper Smelters (Kennecott Copper, Utah)
Source Type: Main stack, air pollution control equipment, and other emission sources
Emission Measurement/Quantification System: 1) For main stack requires SO_2 and NO_x CEMS and stack volumetric flow rates (stack gas temperature and velocity measurement instrumentation). 2) Requires at least one pressure drop and one liquid flow observation per day for each operating scrubber. 3) Requires SO_2 and sulfuric acid stack testing for the following emissions units: Liberator, Cathode Washing, Anode Scrap Washing, Precious Metals Recovery, Silver Production. Stack tests are conducted every 3 years in accordance with 40 CFR 60, Appendix A (Method 1, Method 8, and Method 2).
Averaging Times: 3 hour average, 24 hour calendar day average and annual average
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: None Specified For stack testing, the pollutant concentration is multiplied by the volumetric flow rate and specified conversion factors.
Procedures for Addressing Missing and Invalid Data: Must measure at least 95% of the hours during which emissions occurred in any month. Failure to measure any 18 consecutive hours of emissions data shall constitute a violation. Any hours for which the emissions data are greater than 20% in error will be considered to have not been measured. During periods of malfunction or maintenance, stack gas flow rate may be estimated. These estimates will be considered as measurements. No more than 10% of the flow rates in any one month shall be estimated. If the pressure drop or liquid flow rate deviates from acceptable ranges, the cause must be determined corrective action must be taken immediately. If they remain out of range for greater than 48 hours, it shall be considered a deviation from the permit. Alternative sampling methods approved in writing may be used to supplement monitor availability.

Recordkeeping and Reporting Requirements: Requires semi-annual reports for SO_2 emissions including deviations from permit requirements. Requires stack testing report be submitted within 60 days of test including results as compared to limits and compliance status. Report must include all raw data. Requires electronic quarterly CEMS audit report. Report shall include: 1) Source information, 2) CEMS information (channel, manufacturer, model/serial number, span, installation dates and locations), 3) periods of span exceedances, system outages, malfunctions, or modifications, 4) system performance specification audits, 5) summary of excess emissions including magnitude and duration, 6) description explaining each event of monitor unavailability or excess emissions. Requires monthly report for 1) date, place, time, and operating conditions for sampling, measurement and analysis, 2) results of each measurement or monitoring system and performance of such systems, 3) calculations used to derive the estimated flow rates and periods where flow rate was estimated, 4) deviation of scrubber performance. For CEMS, must maintain a file of all: 1) parameters for each continuous monitoring system and monitoring device, 2) performance test measurements, 3) continuous monitoring system performance evaluations, 4) continuous monitoring system or monitoring device calibration checks, and 5) adjustments and maintenance conducted on these systems or devices. The file shall be retained for at least two years. Additionally, the following data shall also be recorded: 1) The total number of hourly periods during the month in which measurements were not taken, 2) The reason for measurement loss in each period greater than three continuous hours of loss, 3) The dates and number of exceedances on which the 3 and 24 hour emissions averages exceeded the applicable emission level, 4) All conversion values used to derive the 3 and 24 hour average emissions for SO_2, including temperature and differential pressure of stack gases, 5) Support information including all calibration and maintenance records, all original strip-charts or appropriate recordings for continuous monitoring instrumentation. The records of all required monitoring data, support information, and copies of all reports must be retained for least 5 years
Initial Performance Testing: SO_2 CEMS shall meet 40 CFR Part 60, Appendix B, "Performance Specification 2 - Specifications and Test Procedures for SO_2 and NO_x Continuous Emission Monitoring Systems in Stationary Sources." Flow monitor shall meet 40 CFR Part 52 Appendix E. Pressure drop and liquid flow rate for each scrubber shall be observed and recorded at the time of any compliance stack testing.

Periodic Calibration: CEMS shall meet 40 CFR 60 Appendix F. Calibration shall be performed once per day and the hours during which calibration is performed shall be considered as measured if at least 40 minutes of data are measured for each of those hours. Pressure drop and liquid flow rate shall be calibrated in accordance with manufacturer's instructions.
Audits: Conduct Relative Accuracy Test Audits (RATA) and quarterly Relative Accuracy Audits (RAA) or Cylinder Gas Audits (CGA) following Title 40 CFR 60 Appendix F. Conduct Performance Specification in Appendix E of 40 CFR 52 procedures on the stack gas flow rate measurement system in the event that the results of the quarterly and annual tests demonstrate that the SO_2 monitoring system is not performing properly.
Other Appropriate Quality Control and Quality Assurance Measures: None specified
Cost Analysis: Not Available

Table II-2
Monitoring Requirements for Acid Plant at Kennecott Copper in Utah

Primary Source Category: Copper Smelters (Kennecott Copper, Utah.)
Source Type: Sulfuric Acid Plant
Emission Measurement/Quantification System: SO_2 CEMS and flow monitor Stack testing of SO_2 concentration and flow rate every three years using in accordance with 40 CFR 60, Appendix A, (Method 1, Method 8, and Method 2).
Averaging Times: 1-hour averages computed from four or more data points equally spaced over each 1-hour period. 6-hour average calculated as arithmetic mean of 6 contiguous one-hour average SO_2 CEMS concentrations. 24-hour average calculated as averages of 4 consecutive 6-hour periods of each operating day. Annual average
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: For stack testing, the pollutant concentration is multiplied by the volumetric flow rate and specified conversion factors.
Procedures for Addressing Missing and Invalid Data: Alternative sampling methods approved in writing may be used to supplement monitor availability.
Recordkeeping and Reporting Requirements: Requires semi-annual reports for SO_2 emissions including deviations from permit requirements. Requires stack testing report be submitted within 60 days of test including results as compared to limits and compliance status. Report must include all raw data. Requires electronic quarterly CEMS audit report. Report shall include: 1) Source information, 2) CEMS information (channel, manufacturer, model/serial number, span, installation dates/locations), 3) periods of span exceedances, system outages, malfunctions, or modifications, 4) system performance specification audits, 5) summary of excess emissions including magnitude and duration, 6) description explaining each event of monitor unavailability or excess emissions. For CEMS, must maintain a file of all: 1) parameters for each continuous monitoring system and monitoring device, 2) performance test measurements, 3) continuous monitoring system performance evaluations, 4) continuous monitoring system or monitoring device calibration checks, and 5) adjustments and maintenance conducted on these systems or devices. The file shall be retained for at least two years.

Initial Performance Testing: SO_2 CEMS shall meet 40 CFR Part 60, Appendix B, "Performance Specification 2 - Specifications and Test Procedures for SO_2 and NO_x Continuous Emission Monitoring Systems in Stationary Sources"
Periodic Calibration: SO_2 CEMS shall meet 40 CFR Part 60, Appendix F. A monitor which fails the daily calibration drift test shall be declared out-of-control, and the out-of-control period shall be documented in the State electronic data report. Corrective action shall be taken promptly. Automatically check and record the zero and span calibration drifts (CD) at least once daily in accordance with the manufacturer's procedure. Adjust zero and span drift, at a minimum, whenever the 24-hr zero drift or 24-hr span drift exceeds 100 parts per million (ppm).
Audits: Conduct quarterly audits for the SO_2 CEMS including relative accuracy test audit (RATA). An alternate test (cylinder gas audit or relative accuracy audit) may be conducted in three of the four calendar quarters in place of conducting RATA. Performance specification tests and audits shall be conducted so that the entire continuous monitoring system is concurrently tested.
Other Appropriate Quality Control and Quality Assurance Measures: Preventive maintenance of CEMS (including spare parts inventory) Program of corrective action for malfunctioning CEMS
Cost Analysis: Not Available

Table II-3
Monitoring Requirements for Stack, Hoods, and Fugitive Emissions at Copper Smelters in Arizona

Primary Source Category: Copper Smelters, Arizona
Source Type: Air Pollution Control Equipment, Hoods, and Fugitive Emissions
Emission Measurement/Quantification System: 1) Requires a material balance for sulfur (See Attachments A and B). 2) Requires a measurement system for continuously monitoring SO_2 concentrations and stack gas volumetric flow rates of the following: a. outlet of each piece of sulfur dioxide control equipment b. captured fugitive emissions (hoods) c. converter roof fugitive emissions. 3) At each point in the facility where a means exists to bypass the sulfur removal equipment, the bypass shall be instrumented and monitored to detect and record all periods that the bypass is in operation.
Averaging Times: hourly, 3-hour and annual averages Hourly averages based on one measurement of SO_2 concentration and stack gas flow rate reading in each 15-minute period. Requires 45 minutes of monitoring in each hour.
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: Annual average SO_2 emissions = average SO_2 emissions for all hours measured during the compliance period ending on that day. 3-hour SO_2 emissions averages = at the end of each clock hour, average hourly SO_2 emissions for the preceding three consecutive hours. Actual cumulative occurrence and emission level = sum total of SO_2 emissions from the smelter processing units and SO_2 control and removal equipment. The captured fugitive emissions shall be included as part of the total plant emissions, but not the uncaptured fugitive emissions and those emissions due to the use of fuel for space heating or steam generation. Periods of malfunction, startup, shutdown or other upset conditions shall be included in the determination.
Procedures for Addressing Missing and Invalid Data: Failure to measure at least 95% of the hours during which emissions occurred in any month, using the CEMS shall constitute a violation. Failure to measure any 12 consecutive hours of emissions in accordance with the requirements in this subsection shall constitute a violation. Maintain sufficient spare parts or duplicate systems for the continuous monitoring equipment to allow for the replacement within six hours of any monitoring equipment part which fails or malfunctions.

Recordkeeping and Reporting Requirements: Maintain a record of all average hourly emissions measurements for 5 years Monthly reporting requirements (1) the annual average emissions (expressed in lb/hr) as calculated at the end of each day of the month; (2) The total number of hourly periods during the month in which measurements were not taken and the reason for loss of measurement for each period; (3) The number of three-hour emissions averages which exceeded each of the applicable emissions levels for the compliance periods ending on each day of the month being reported; (4) The date on which a cumulative occurrence limit was exceeded during the month being reported. (5) All times bypass was in operation and the reason for the bypass.
Initial Performance Testing: Meet 40 CFR Part 60, Appendix B: “Performance Specification 6 - Specifications and Test Procedures for Continuous Emission Rate Monitoring Systems in Stationary Sources” including: (1) Performance and Equipment Specifications (2) CD Test Procedure, and (3) RA Test Procedure, and "Performance Specification 2 - Specifications and Test Procedures for SO_2 and NO_x Continuous Emission Monitoring Systems in Stationary Sources" including: (1) Installation and Measurement Location Specifications, (2) Performance and Equipment Specifications, (3) Performance Specification Test Procedure, (4) The CEMS Calibration Drift Test Procedure, (5) Relative Accuracy Test Procedure
Periodic Calibration: Meet 40 CFR Part 60, Appendix F Automatically check, quantify, and record the zero and span calibration drifts at least once daily. If greater than 2Xs the specified limit, the zero and span must be adjusted. Also subject to the manufacturer’s recommended zero adjustment and calibration procedures at least once per 24-hour operating period unless manufacturer specifies calibration at shorter intervals.
Audits: Conduct CEMS audits once per quarter including Relative Accuracy Test Audit (RATA) must be conducted at least once every four calendar quarters. Cylinder Gas Audit (CGA), if applicable, may be conducted in three of four calendar quarters Relative Accuracy Audit (RAA) may be conducted three of four calendar quarters
Other Appropriate Quality Control and Quality Assurance Measures: Preventive maintenance of CEMS Program of corrective action for malfunctioning CEMS
Cost Analysis: Not Available

Table II-4
Monitoring Requirements for Acid Plant Tail Gas at Copper Smelters in Arizona

Primary Source Category: Copper Smelters (Ray Complex Hayden Smelter, Arizona.)
Source Type: Sulfuric Acid Plant Tail Gas
Emission Measurement/Quantification System: SO_2 CEMS installed at the acid plant tail gas monitoring station to monitor emissions from the Inco oxygen flash furnace.
Averaging Times: 1-hour averages computed from four or more data points equally spaced over each 1-hour period. 6-hour average calculated as arithmetic mean of 6 contiguous one-hour average SO_2 CEMS concentrations. 24-hour average calculated as averages of 4 consecutive 6-hour periods of each operating day. Annual average
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: None Specified
Procedures for Addressing Missing and Invalid Data: If the SO_2 CEMS has an excessive audit inaccuracy, corrective action shall be taken followed by a RATA and test audit. If inaccuracies occur for 2 consecutive quarters, the QA procedures shall be rewritten or CEMS replaced.
Recordkeeping and Reporting Requirements: Required to submit semi-annual compliance certification, quarterly excess emissions report, and quarterly monitoring report. Monitoring report includes CEMS data accuracy audits (RATA), results from EPA performance audit samples, applicable reference methods, summary of all corrective actions. Required to keep records of monitoring information including, but not limited to, the following: 1. The date, place as defined in the permit, and time of sampling or measurements; 2. The date(s) analyses were performed; 3. The name of the company or entity that performed the analyses; 4. A description of the analytical techniques or methods used; 5. The results of such analyses; 6. The operating conditions as existing at the time of sampling or measurement; 7. Occurrence and duration of any startup, shutdown, or malfunction in operations, any malfunction of the air pollution control equipment, or any periods during which a continuous monitoring system or monitoring device is inoperative; 8. Calibration and maintenance records, strip-chart recordings or other data recordings for continuous monitoring instrumentation, and copies of all reports; and 9. Continuous monitoring system performance evaluations and performance testing measurements. Must retain records of all required monitoring data and support information for a period of at least 5 years.
Initial Performance Testing: SO_2 CEMS shall meet 40 CFR Part 60, Appendix B, "Performance Specification 2 - Specifications and Test Procedures for SO_2 and NO_x Continuous Emission Monitoring Systems in Stationary Sources"

Periodic Calibration: SO_2 CEMS shall meet 40 CFR Part 60, Appendix F Automatically check and record the zero and span calibration drifts (CD) at least once daily in accordance with the manufacturer's procedure. Adjust zero and span drift, at a minimum, whenever the 24-hr zero drift or 24-hr span drift exceeds 100 ppm.
Audits: Conduct quarterly audits for the SO_2 CEMS including relative accuracy test audit (RATA), and cylinder gas audit (CGA) or relative accuracy audit (RAA).
Other Appropriate Quality Control and Quality Assurance Measures: Preventive maintenance of CEMS (including spare parts inventory) Program of corrective action for malfunctioning CEMS
Cost Analysis: Not Available

Attachment A
AMA Proposed Protocol For Determining Copper Smelter SO_2 Emissions
Sulfur Balance Method

I. DETERMINATION OF SULFUR EMISSIONS FOR THE SMELTER AS A WHOLE SHALL BE SUBJECT TO THE FOLLOWING CONDITIONS:

A. The emission sum shall apply to all process sulfur emitted into the ambient air from smelter processing units and sulfur control and removal equipment associated with the smelting process. The total monthly amount of sulfur emissions is equal to the weight of the total sulfur introduced into the smelting process in any calendar month minus the weight of all sulfur removed from the smelting process streams in that month in any physical form, plus or minus the weight of the sulfur contained in any month-month decrease or increase necessary to indicate materials in process. Removed sulfur shall include but not be limited to sulfur contained in slag, blister copper, copper anodes, reverts, sulfuric acid, liquified sulfur dioxide, elemental sulfur, flue dust, precipitator dust, acid plant sludge, scrubber effluent and absorption plant purge. All sulfur not listed above as removed, including fugitive sulfur emissions, shall be considered as emissions to the ambient air.

B. Material balances for sulfur described in A.1. above shall be obtained in accordance with the procedures listed in below.

C. Average daily emissions are to be determined by dividing the total monthly emissions by the number of operating days in the particular month. An operating day is defined as any day in which sulfur containing feed is introduced into the smelting process.

II. CALCULATING INPUT SULFUR

Total sulfur input is the sum of the product of the weight of each sulfur bearing material introduced into the smelting process as calculated in A.1 below multiplied by the fraction of sulfur contained in that material as calculated in A.2 below plus the amount of sulfur contained in fuel utilized in the smelting process as calculated in A.3 below.

A. Material Weight

All sulfur bearing materials, other than fuels, introduced into the smelting process shall be weighed. Such weighing shall be subject to the following conditions:

1. Weight shall be determined on a belt scale, rail or truck scales, or other weighing device.
2. Weight shall be determined within an accuracy of ±5 percent.
3. All devices or scales used for weighing are to be calibrated to manufacturer's specifications. Scales will be calibrated at least quarterly.

4. Sulfur bearing materials subject to being weighed shall include but not be limited to concentrate, cement copper, reverts which are discarded and not part of the internal circulating load, precipitates, and miscellaneous outside products. Materials such as limestone and silica flux which are mixed with a charge of sulfur bearing materials shall be weighed and reported.

B. Sulfur Content

The sulfur content of all sulfur bearing materials introduced into the smelting process shall be calculated using the following steps:

1. Sampling - The procedure to be followed in sampling is dependent upon the input vehicles for the sulfur bearing material.

    a. Railcar - The smelter operator shall collect a sample using an auger, pipe sampling, or other representative method. A minimum of two points per car will be taken and combined. One to twenty cars from the same source will be combined into one lot.

    b. Truck - The smelter operator shall collect a sample using an auger, pipe sampling, or other representative method. Shipments from offsite may be sampled at the mine site provided each truckload is sampled. Samples are combined into lots from trucks delivering material from the same source. For fluxes from smelter controlled mines, one truckload per day are sampled.

2. Sample Preparation - Each total sample shall be prepared for analysis in the following manner:

    a. If necessary, the sample shall be crushed to minus quarter inch particles.

    b. Each sample is to be thoroughly blended in a roto-cone blender or similar device.

    c. A blended composite sample is to be prepared based on individual sample weight and moisture. Material to be used in the composite sample is to be cut with a sample scoop or knife and used to make an 1800-2400 gram composite sample for each lot.

    d. Each composite sample is to be dried and then pulverized to minus 80 mesh using a roto-disc pulverizer or similar equipment and then blended in a roto-cone blender or similar equipment.

    e. A 200 gram portion is to be cut from the composite sample for analysis.

3. Sample Analysis.

   a. The sample shall be analyzed to determine sulfur content using X-ray Fluorescence Spectroscopy, Inductively Coupled Plasma Spectroscopy, or a LECO Sulfur Analyzer.

4. Sulfur Determination - The sulfur content of all feed material treated per month will be determined by month end physical inventories in conjunction with certified scales for bed contents. Physical inventory determines beginning and ending bed for each month and all beds processed during the month, together with inventory changes for secondaries. Based upon individual lot numbers for each material processed (i.e., concentrates, reverts, purchased secondaries, recyclable material, and fluxes) the composite analysis will be used to determine sulfur input.

C. Fuel Sulfur Content

Sulfur in fuels shall be calculated by multiplying the amount of fuel delivered to the process by the fraction of sulfur in the fuel as reported to the smelter operator by the fuel's supplier. The sulfur content determination shall be accurate to within ±5 percent.

III CALCULATING REMOVED SULFUR

Total removed sulfur is the sum of the sulfur removed in each of the following products as determined by each process set forth below.

A. Furnace Slags

1. The weight of the slag shall be determined using a count of furnace slag ladles. The weight used for slag in slag ladles will be determined periodically.

2. A sample will be collected from each slag ladle during skimming operations and may be combined into a daily composite sample.

3. The sample shall be prepared and analyzed for sulfur. The sample will be dried and pulverized using a roto-disc pulverizer. A 200 gram sample will then be split out using a Jones splitter, or equivalent.

4. The sample will be analyzed as in B.3 above.

B. Scrubber Sludge

1. For sludge that is collected (as a slurry), clarified, and filtered before drying, a weight will be determined. If the material is trucked to a drying facility, the sludge will be sampled each time a truck is filled. A weight will be determined for a truckload. The sample will be prepared and analyzed for sulfur using the procedures in II.B.3 above.

2. If scrubber sludge is managed in a manner other than as set forth in III.B.1 above, it shall be quantified, sampled, and analyzed pursuant to generally acceptable methods.

C. Strong Acids

1. The daily production of acid shall be determined by using either a flowmeter which measures all acid added to the storage tanks from which trucks or rail cars are loaded, or a daily inventory increased by the amounts of acid shipped or otherwise transferred during that day.

2. The meter reading or daily inventory will be accurate to within ±5 percent.

3. Strong acid samples will be analyzed for sulfuric acid concentration using specific gravity, sonic (sound velocity) or other acceptable analytical methods.

4. The acid stream will be analyzed twice per shift to check sensor accuracy.

5. A product sample will be sent to the laboratory for analysis daily.

6. All flow meters, density gauges, sonic sensors, pressure sensors, etc., used in determining the sulfur balance will be calibrated according to manufacturer's specifications.

D. Weak Acids

1. The amount of weak acid discharged from the acid plant and scrubber systems is to be determined through flow meters.

2. Flow meters will be calibrated as in C.6 above.

3. A 100 ml sample of weak acid shall be collected daily and combined in a sample container to form a monthly composite sample which is analyzed for sulfur content using the Barium Sulfate Gravimetric Method or its equivalent.

E. Sulfur in Copper Production

1. The weight of copper produced is to be determined by weight of copper cast to an accuracy of within ±5 percent.

2. The weight and number of castings shall be recorded.

3. For blister or anode castings containing more than 100 ppm sulfur the following procedure will be followed. Three sample bars per charge are to be obtained at the beginning, middle, and end of each pour. A portion (approximately 1 gram) from each sample is to be analyzed for sulfur content using a LECO Sulfur Analyzer with an induction furnace to volatilize the sulfur and measure the resultant compound using Infrared Spectroscopy to

an accuracy of within 50 percent. As an alternative, a slab cut from the bar will be analyzed using an Optical Emission Spectrometer (using time resolved spectroscopy). Other analytical techniques may be used if approved.

4. If the average concentration in anode castings has been less than 100 ppm during the preceding 12-month period, sampling and analysis may be reduced to a monthly composite or a 50 ppm value may be assumed without sampling.

F. Materials in Process

1. Total tonnage of materials in process shall be determined by physical inventory on the first day of each month.

2. A monthly change of in-process inventory shall be calculated for each material in process by taking the difference between the inventory from each material in process on the first day of the preceding month and multiplying that difference by the monthly composite sulfur assay for that material.

3. The change of monthly in-process inventory must be accurate to within ±50 percent.

Attachment B
QA/QC Plan for Sulfur Analyses at ASARCO Hayden Laboratory

Sulfuric Acid - Shipments and Production

1. Operation: The Sulfuric Acid Analyzer will be operated as per manufacturer's instructions.

2. Blank Analyses: A blank analysis consisting of deionized water will be analyzed daily. This will be compared to the velocity of sound in water and must fall within ± 5% of the published value.

3. Calibration Verification Sample: A standard sample will be analyzed with each set of samples. The Calibration Verification Sample must fall within ± 2% of its control value. The results of the analysis will be plotted on a control chart to indicate the control value is within three (3) standard deviations.

4. Duplicates: Every twentieth (20) sample, or one sample from each analytical set, will be analyzed in duplicate. The relative standard deviation will be calculated and must fall within ± 20%.

5. Quality Control Sample: A quality control sample will be analyzed quarterly. The analysis will compare within ± 10%. (blind note: JTBaker Sulfuric acid 9681-02)

6. Quality Assurance: When control limits are exceeded, the analysis will be repeated. If necessary, a supervisory chemist will be notified and the necessary steps will be taken to bring the analysis within control. No analyses will be reported or used as valid data, until the method is found to be under control.

LECO Sulfuric Analyzer - Concentrates and By-Products

1. Operation: The LECO Sulfur Analyzer will be operated as per manufacturers instructions.

2. Blank Analyses: A blank analysis consisting of the crucible accelerator and cover will be analyzed with each set of samples. The blank value will be calculated assuming a 0.500 gm weight. Blanks that are above 0.10% must be replaced and the analysis repeated.

3. Calibration Verification Sample: A standard sample will be analyzed with each set of samples. The Calibration Verification Sample must fall within ± 10% of its control value. The results of the analysis will be plotted on a control chart to indicate the control value is within three (3) standard deviations.

4. Duplicates: All samples will be analyzed in duplicate. The relative standard deviation will be calculated and must fall within ± 20%.

5. Quality Control Sample: A quality control sample will be analyzed quarterly. The analysis will compare within ± 10%.

6. Quality Assurance: When control limits are exceeded, the analysis will be repeated. If necessary, a supervisory chemist will be notified and the necessary steps will be taken to bring the analysis within control. No analyses will be reported or used as valid data, until the method is found to be under control.

Weak Acid Solutions - Process Solutions

1. Operation: The Sulfuric Acid Analyzer will be operated as per manufacturer's instructions.

2. Blank Analyses: A blank analysis consisting of deionized water will be analyzed daily. This will be compared to the velocity of sound in water and must fall within ± 5% of the published value.

3. Calibration Verification Sample: A standard sample will be analyzed with each set of samples. The Calibration Verification Sample must fall within ± 2% of its control value. The results of the analysis will be plotted on a control chart to indicate the control value is within three (3) standard deviations.

4. Duplicates: Every twentieth (20) sample, or one sample from each analytical set, will be analyzed in duplicate. The relative standard deviation will be calculated and must fall within ± 20%.

5. Quality Control Sample: A quality control sample will be analyzed quarterly. The analysis will compare within ± 10%. (blind note: JTBaker Sulfuric acid 9681-02)

6. Quality Assurance: When control limits are exceeded, the analysis will be repeated. If necessary, a supervisory chemist will be notified and the necessary steps will be taken to bring the analysis within control. No analyses will be reported or used as valid data, until the method is found to be under control.

CHAPTER III
SULFUR PLANTS

Sulfur plants are located at refineries, natural gas processing plants and oil and gas production facilities. The sulfur in the fuel is first removed by scrubbing with an amine solution. Then H_2S is removed from the waste gas stream by the sulfur recovery plant. Most plants use the Claus sulfur recovery method which oxidizes H_2S into elemental sulfur, SO_2 and water. The elemental sulfur recovered is often sold as a by-product. The tail gas from the sulfur recovery plant contains sulfur dioxide and other reduced sulfur compounds. After the Claus plant, the residual H_2S in the waste gas may be further treated in a "tail gas" treatment plant like the SCOT or Stretford-Beavon process. H_2S conversion efficiencies of up to 99.9 percent of sulfur are possible. Residual H_2S may also be flared.

The NSPS for petroleum refineries (40 CFR 60 Subpart J) includes SO_2 standards for Claus sulfur recovery plants. Monitoring requirements in the NSPS rule for refineries are summarized in Table III-1. The NSPS requires gaseous CEMS for sulfur recovery plants. The constituents monitored vary according to the control equipment installed on the plant, but include SO_2, reduced sulfur compounds, and O_2. The NSPS does not require flow monitoring because the flow levels are unnecessary for evaluating compliance.

The NSPS for natural gas processing plants (40 CFR 60 Subpart LLL) includes standards for sulfur recovery plants. Monitoring requirements in the NSPS rule for natural gas processing plants are summarized in Table III-2. The monitoring requirements specify measuring the sulfur production rate and H_2S concentration daily and using a continuous monitoring device to measure average acid gas flow rate from the sweetening unit hourly. For units with oxidation or reduction control system, the requirements are similar to those for refineries: CEMS for SO_2 and O_2, or CEMS for TRS, except that the values are reported as mass per unit of time, and thus are more amenable to use in an emissions trading program.

Refineries are located in California, Colorado, New Mexico, Utah and Wyoming. Natural gas processing plants are located in New Mexico, Utah and Wyoming. Oil and gas production facilities are located in California, Colorado, New Mexico, Utah and Wyoming. In California's SCAQMD, sulfur plants are subject to the RECLAIM SO_2 program. Generally, sources use SO_2 and flow CEMS under this program for these units.

In addition, New Mexico submitted monitoring requirements for sulfur plants at natural gas processing plants and refineries which are provided in Table III-3 and Table III-4. Sulfur plants at both refineries and natural gas processing plants may be required to use CEMS, either as part of NSPS compliance, or if subject to new source review permitting. Other sources typically use portable analyzer checks or other approaches.

Table III-1
NSPS Monitoring Requirements for Sulfur Recovery Plants at Refineries

Primary Source Category: Refineries 40 CFR 60 Subpart J New Source Performance Standard
Source Type: Claus sulfur recovery plants
Emission Measurement/Quantification System: 1) with oxidation or reduction control system followed by incineration: CEMS for SO_2 (dry basis, 0% excess air) and O_2 (for correcting the data for excess air) Span values: 500 ppm SO_2 and 25% O_2. 2) with reduction control systems not followed by incineration: CEMS for reduced sulfur (dry basis, 0% excess air) and O_2 emissions. Span values: 450 ppm reduced sulfur and 25% O_2. (If performance specification test yields O_2 concentrations below 0.25%, O_2 not required) **or** CEMS using an air or O_2 dilution and oxidation system to convert the reduced sulfur to SO_2 (dry basis, zero percent excess air) and O_2 CEMS for correcting the data for excess oxygen. Span values: 375 ppm SO_2 and 25% O_2.
Averaging Times: Calculate 1-hr average of SO_2 concentration from 4 or more samples collected periodically during hour. Compliance determined by average of 12-hour period Calculate 7-day rolling average basis Requires a minimum of 22 valid days of data shall be obtained every 30 rolling successive calendar days
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: None
Procedures for Addressing Missing and Invalid Data: Requires sources to account for emissions during periods when there are no valid data (missing data periods) due to the monitor not operating or operating out of control.
Recordkeeping and Reporting Requirements: Required to submit a written report of the results of the performance evaluation within 60 days of completion. Required to submit semi-annual report specifying periods where monitoring values exceed limits for a specified monitoring period and periods of missing data

Initial Performance Testing: For SO_2 and TRS CEMS: Performance Specification 2 Reference Methods (RM) 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Conduct a minimum of nine sets of all necessary RM test runs. Correlate the CEMS and the RM test data. Calculate the mean difference between the RM and CEMS values. Calibration Drift (CD) - while unit is operating at more than 50 percent of normal load, determine the magnitude of the CD once each day (at 24-hour intervals) for 7 consecutive days. CD must not drift or deviate from the reference value of the calibration gas by more than 5 percent of the established span value for 6 out of 7 test days.
Periodic Calibration: Calibration of CEMS as specified by manufacturer Automatically check, quantify, and record the zero and span calibration drifts at least once daily. If greater than 2Xs the specified limit, the zero and span must be adjusted.
Audits: Conduct a performance evaluation of the CEMS during or within 30 days any performance test required under §60.8 Conduct CEMS audits once per quarter Relative Accuracy Test Audit (RATA) must be conducted at least once every four calendar quarters. Cylinder Gas Audit (CGA), if applicable, may be conducted in three of four calendar quarters Relative Accuracy Audit (RAA) may be conducted three of four calendar quarters Take corrective action, as required, to correct any problems with CEMS
Other Appropriate Quality Control and Quality Assurance Measures: Preventive maintenance of CEMS (including spare parts inventory). QC for data recording, calculations, and reporting. Program of corrective action for malfunctioning CEMS.
Cost Analysis: a. Installed Capital Cost b. Direct Operating Cost c. Total Annualized Cost d. Equipment Life e. Year Dollars f. Discount Rate

Table III-2
NSPS Monitoring Requirements
for Sulfur Plants at Natural Gas Processing Plants

Primary Source Category: Natural Gas Processing 40 CFR 60 Subpart LLL
Source Type: Sulfur Plants
Emission Measurement/Quantification System: Requires measuring the following on a daily basis: 1) accumulation of sulfur product over each 24-hour period using an instrument to measure sulfur production rate or manual measurement of sulfur liquid levels in storage tanks. 2) H_2S concentration in the acid gas from the sweetening unit for each 24 hour period by collecting and analyzing at least one sample using specified method. 3) average acid gas flow rate from the sweetening unit using a continuous monitoring device that records hourly flow rate. Optional H_2S measurement technique is Tutwiler procedure For unit with oxidation or reduction control system followed by incinerator, requires the following: 1) CEMS for SO_2 (expressed as equivalent sulfur mass flow rate) Span value of 30% to 70% of unit emission limit 2) monitoring device to measure temperature of gas leaving combustion zone of incinerator **or** CEMS for TRS (upon promulgation of performance spec. for CEMS of TRS at sulfur recovery plants) For unit with oxidation or reduction control system **not** followed by incinerator; 1) CEMS for reduced sulfur compounds as SO_2 (expressed as equivalent sulfur mass flow rate) (upon promulgation of performance spec. for CEMS of TRS at sulfur recovery plants)
Averaging Times: Daily measurement of sulfur production rate Daily sampling of H_2S Hourly measurement of acid gas flow rate averaged over 24-hour period For CEMS, hourly average based on 15-minute sampling intervals
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: Daily average sulfur feed rate = average daily flow rate x average daily H_2S concentration x CF Daily average SO_2 reduction efficiency = sulfur production rate ÷ average daily sulfur feed rate x CF, where CF=conversion factor For unit with oxidation or reduction control system followed by incinerator*:* Total sulfur emission rate = SO_2 + TRS (both as equivalent sulfur mass flow rate)
Procedures for Addressing Missing and Invalid Data: At least 2 data points required to calculate hourly average for CEMS At least 18 1-hour averages to calculate 24-hour averages No procedures specified

Recordkeeping and Reporting Requirements: Records of measurements and calculations must be retained for 2 years Submit written report for excess emissions, when emission reduction efficiency is less than minimum, or for temperature of combustion zone is out of range
Initial Performance Testing: Temperature monitor must be manufacturer certified as ± 1% accurate for operating temperature range Performance Specification 2 for SO_2 CEMS Reference Methods (RM) 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Conduct a minimum of nine sets of all necessary RM test runs. Correlate the CEMS and the RM test data. Calculate the mean difference between the RM and CEMS values. Calibration Drift (CD) - while unit is operating at more than 50 percent of normal load, determine the magnitude of the CD once each day (at 24-hour intervals) for 7 consecutive days. D must not drift or deviate from the reference value of the calibration gas by more than 5 percent of the established span value for 6 out of 7 test days.
Periodic Calibration: Monitoring devices must be calibrated at least annually according to manufacturers specifications. Automatically check, quantify, and record the zero and span calibration drifts at least once daily. If greater than 2Xs the specified limit, the zero and span must be adjusted.
Audits: Conduct a performance evaluation of the CEMS during or within 30 days any performance test required under §60.8 Conduct CEMS audits once per quarter Relative Accuracy Test Audit (RATA) must be conducted at least once every four calendar quarters. Cylinder Gas Audit (CGA), if applicable, may be conducted in three of four calendar quarters Relative Accuracy Audit (RAA) may be conducted three of four calendar quarters Sampling and analysis methods accuracy audit
Other Appropriate Quality Control and Quality Assurance Measures: Preventive maintenance of CEMS (including spare parts inventory). QC for data recording, calculations, and reporting. Program of corrective action for malfunctioning CEMS.
Cost Analysis: a. Installed Capital Cost b. Direct Operating Cost c. Total Annualized Cost d. Equipment Life e. Year Dollars f. Discount Rate

Table III-3
Monitoring Requirements for Sulfur Plants at Natural Gas Processing Plants in the State of New Mexico

Primary Source Category: Natural Gas Processing Plants/New Mexico
Source Type: Sulfur Plants
Emission Measurement/Quantification System: CEMS, Overall System Integrity (OSI) & Sulfur Recovery Efficiency (SRE)
Averaging Times: The monitor shall complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period or less. One-hour averages shall be computed from four or more data points equally spaced over each one-hour period. The data from the SO_2 stack gas monitor and flow meter shall be analyzed on an hourly basis for SO_2 concentration and volume flow rate. The minimum data capture for the CEMS shall be 95%. OSI monthly equipment inspections for Non-NSPS Subpart LLL sources and daily for sources subject to LLL. State regulation(s) require the measurement (frequency varies from daily to quarterly) of the following Sulfur Recovery Unit (SRU) parameters: incinerator temperature, excess O_2 level in the incinerator, acid gas flow rate and H_2S concentration and a running tally of the accumulated elemental sulfur recovered.
Consideration of Batch, Seasonal, and Cyclical Operations: None.
Calculations Used to Determine Quarterly and Annual Mass Emissions: SO_2 emissions = Daily H_2S volume * H_2S concentration (PPMV) * H_2S (MW) * 64/32 / E^6 * 385 (F factor) * 24 hrs/day.
Procedures for Addressing Missing and Invalid Data: Periods when the SRU and/or CEMS are not operational are excluded from the data capture calculation and records shall be kept for these occurrences in accordance with 40 CFR 60.7
Recordkeeping and Reporting Requirements: The permittee shall maintain records of all SRU inspections and tests required and records of any adjustments, repairs, or replacements needed to bring the SRU into compliance with the permit conditions. All records shall show the date of inspection and the name of the person(s) who carried out the inspection. If the permittee keeps records more frequently than the minimum frequency required, the permittee shall also keep these records for Department inspection. The permittee shall maintain records of the SRU operating parameters and equipment and operational inspections and results of the periodic mass emission tests on the incinerator. The permittee shall maintain records showing calibration results on any instrument or apparatus used to determine pollutant concentration species, process stream flows, or temperatures. For sources subject to Subpart LLL: The permittee shall maintain records of all calibrations carried out on the SO_2 CEMS. The record shall show the date of calibration, and calibration gas data (concentration, gas supplier name and address, mixture serial number and expiration date). Compliance with 40 CFR 60.7 is required. The permittee shall maintain records of all service and maintenance performed on the CEMS, including a description of the problem requiring the maintenance or repair. Reports of equipment and/or operational inspections shall briefly summarize in chronological order the results of all SRU inspections noting any adjustments needed to bring the SRU into compliance with permit conditions.

Reports of periodic emissions tests shall summarize in tabular form, for each test, the SO_2 concentrations expressed in ppm. The table shall include the incinerator combustion zone temperature, the level of excess air, and the SRU bed temperatures. The report of the initial or subsequent emissions tests shall conform to the standard format specified by the Department, <u>Standard Operating Procedure: Contents of Stack Test Reports</u>. The SO_2 CEM shall comply with the reporting requirements of 40 CFR 60.7 regarding submission of excess emissions reports. Reports of all required monitoring activities for this facility, except those reports required by an NSPS, shall be submitted to the Department according to the schedule indicated below. Reports required by NSPS Subpart LLL shall be submitted at the frequency required by the appropriate NSPS subpart. Protocols for emissions tests shall be submitted to the Department at least four (4) weeks prior to the scheduled test date with content according to the Department's Standard Operating Procedure for Contents of Stack Test Protocols. If information remains the same as in previously submitted protocols, test protocols shall reflect that fact and show only new information.
Initial Performance Testing: A mass emissions test for SO_2, shall be conducted on the SRU in accordance with EPA Methods 1 through 4, Method 6 (SO_2) contained in 40 CFR Part 60, Appendix A, and with the requirements of Subpart A, <u>General Provisions</u>, Sect. 60.8(f). The SRUs sulfur recovery efficiency and the incinerator's sulfur combustion efficiency shall be determined in accordance with the appropriate subsections of NSPS Subpart LLL, 40 CFR 60.644. Non-NSPS units shall determine the SRUs sulfur recovery efficiency, and the incinerator's sulfur combustion efficiency shall be determined in accordance with the attached <u>Standard Operating Procedure: Sulfur Recovery Unit Performance Testing</u>. The permittee shall notify the Department at least thirty (30) days prior to the test date and allow a representative of the Department to be present at the test. The permittee shall arrange a pre-test meeting with the Department at least thirty (30) days prior to the test date and shall observe the following pre-testing and testing procedures: The test protocol and test report shall conform to the standard format specified by the Department as described in <u>Standard Operating Procedure: Contents of Stack Test Protocols</u>. The most current version of the format may be obtained from the Enforcement Section of the Air Quality Bureau. The permittee shall provide (a) sampling ports adequate for the test methods applicable to the facility, (b) safe sampling platforms, (c) safe access to sampling platforms and (d) utilities for sampling and testing equipment. The stack shall be of sufficient height and diameter so that a representative test of the emissions can be performed in accordance with EPA Method 1. During compliance tests, the following variables shall be measured and recorded and included with the test report: The SRUs bed temperatures (top, middle, and bottom), condenser temperatures, incinerator combustion zone temperature, flow and concentration of acid gas feedstock to SRU, and amount of elemental sulfur recovered. Where necessary to prevent cyclonic flow in the stack, flow straighteners shall be installed. The tests shall be carried out at 90% or greater of the SRUs full operating capacity and at other operating loads as may be specified by the Department at the time of the test or pre-test meeting.
Periodic Calibration: CEMS shall be calibrated daily in accordance with NSPS Subpart A, 40 CFR 60.13(d)(1).

Audits: An SRU with an SO_2 CEMS requires no periodic emissions testing unless the SRU is by itself major for NO_x or CO. If the SRU is by itself major for either NO_x or CO, then NO_x and CO concentration measurements are required even when the incinerator has an SO_2 CEM. The SO_2 {and NO_x and CO} concentration of the incinerator flue gas shall be measured. The measurement may be carried out using a portable flue gas analyzer using the procedures in the most current version of the Bureau's Standard Operating Procedure: Use of Portable Analyzers in Performance Tests. The permittee need only observe those sections relative to sample conditioning, analyzer range and sensitivity, response time, and calibration. The test may also be carried out using any effective procedure approved in advance by the Department. Emissions shall be expressed in ppm. Each test shall be carried out while the SRU is operating at a load representative of the load during the relevant time period. Periodic emissions tests shall be conducted at the intervals in the following schedule: First test: Six (6) months from permit issuance; Second test: Twelve (12) months from permit issuance; Third test: Twenty four (24) months from permit issuance; Fourth test: Forty eight (48) months from permit issuance; All subsequent testing shall follow at twenty-four (24) month intervals. However, the test schedule is contingent on maintaining test data that indicates compliance. If any test indicates non-compliance, the periodic emissions test sequence shall revert to the beginning of the above schedule, starting with the date of the most recent test.
Other Appropriate Quality Control and Quality Assurance Measures: Initial emission testing is required for SRU's that have not been stack tested in the ten years previous to permit issuance. SRU's equipped with CEMS shall be recertified every year in accordance with NSPS Appendix B, 40 CFR 60.
Cost Analysis: Unknown.

Table III-4
Monitoring Requirements for Sulfur Recovery Plants at Refineries in the State of New Mexico

Primary Source Category: Refinery/New Mexico
Source Type: Sulfur Plant
Emission Measurement/Quantification System: Continuous Emissions Monitoring System (CEMS), Overall System Integrity (OSI) & Sulfur Recovery Efficiency (SRE)
Averaging Times: The monitor shall complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period or less. One-hour averages shall be computed from four or more data points equally spaced over each one-hour period. The data from the SO_2 stack gas monitor and flow meter shall be analyzed on an hourly basis for SO_2 concentration and volume flow rate. The minimum data capture for the CEMS shall be 95%. OSI monthly equipment inspections for Non-NSPS Subpart J sources and daily for sources subject to J. State regulation(s) require the measurement (frequency varies from weekly to monthly) of the following Sulfur Recovery Unit (SRU) parameters: feedstock sulfur content entering the sulfur recovery plant, the weight of the recovered sulfur and the concentration of sulfur dioxide and hydrogen sulfide in the exit gas stream or streams.
Consideration of Batch, Seasonal, and Cyclical Operations: None.
Calculations Used to Determine Quarterly and Annual Mass Emissions: SO_2 emissions = Daily H_2S volume * H_2S concentration (PPMV) * H_2S (MW) * 64/32 / E^6 * 385 (F factor) * 24 hrs/day. Also the methods outlined in Subpart J 60.106.
Procedures for Addressing Missing and Invalid Data: Periods when the SRU and/or CEMS are not operational are excluded from the data capture calculation and records shall be kept for these occurrences in accordance with 40 CFR 60.7.
Recordkeeping and Reporting Requirements: The permittee shall maintain records of all SRU inspections and tests required and records of any adjustments, repairs, or replacements needed to bring the SRU into compliance with the permit conditions. All records shall show the date of inspection and the name of the person(s) who carried out the inspection. If the permittee keeps records more frequently than the minimum frequency required, the permittee shall also keep these records for Department inspection. Records of all calibration and maintenance performed for the instruments that measure sulfur flow and concentration into and out of the SRU The permittee shall maintain records of the SRU operating parameters and equipment and operational inspections and results of the periodic mass emission tests on the incinerator. The permittee shall maintain records showing calibration results on any instrument or apparatus used to determine pollutant concentration species, process stream flows, or temperatures. For sources subject to Subpart J: The permittee shall maintain records of all calibrations carried out on the SO_2 CEMS. The record shall show the date of calibration, and calibration gas data (concentration, gas supplier name and address, mixture serial number and expiration date). Compliance with 40 CFR 60.7 is required. The permittee shall maintain records of all service and maintenance performed on the CEMS, including a description of the problem requiring the maintenance or repair. Reports of equipment and/or operational inspections shall briefly summarize, in chronological order, the results of all SRU inspections noting any adjustments needed to bring the SRU into compliance with permit conditions. Reports of periodic emissions tests shall summarize in tabular form for each test the SO_2 concentrations expressed in ppm. The table shall include the incinerator combustion zone temperature, the level of excess air, and the SRU bed temperatures.

The report of the initial or subsequent emissions tests shall conform to the standard format specified by the Department, Standard Operating Procedure: Contents of Stack Test Reports. The SO_2 CEM shall comply with the reporting requirements of 40 CFR 60.7 regarding submission of excess emissions reports. Reports of all required monitoring activities for this facility, except those reports required by an NSPS, shall be submitted to the Department according to the schedule indicated below. Reports required by NSPS Subpart J shall be submitted at the frequency required by the appropriate NSPS subpart.
Initial Performance Testing: A mass emissions test for SO_2, shall be conducted on the SRU in accordance with EPA Methods 1 through 4, Method 6 (SO_2) contained in 40 CFR Part 60, Appendix A, and with the requirements of Subpart A, General Provisions, Sect. 60.8(f). Compliance with the SO_2, H_2S and reduced sulfur standards in 60.104(a)(2) in accordance with the appropriate subsections of NSPS Subpart J, 40 CFR 60.106. Non-NSPS shall determine the SRUs sulfur recovery efficiency, and the incinerator's sulfur combustion efficiency shall be determined in accordance with the attached Standard Operating Procedure: Sulfur Recovery Unit Performance Testing. During compliance tests, the following variables shall be measured and recorded and included with the test report: The SRUs bed temperatures (top, middle, and bottom), condenser temperatures, incinerator combustion zone temperature, flow and concentration of acid gas feedstock to SRU, and amount of elemental sulfur recovered.
Periodic Calibration: CEMS shall be calibrated daily in accordance with NSPS Subpart A, 40 CFR 60.13(d)(1).
Audits: An SRU with an SO_2 CEMS requires no periodic emissions testing unless the SRU is by itself major for NO_x or CO. If the SRU is by itself major for either NO_x or CO, then NO_x and CO concentration measurements are required even when the incinerator has an SO_2 CEM. The SO_2 {and NO_x and CO} concentration of the incinerator flue gas shall be measured. The measurement may be carried out using a portable flue gas analyzer using the procedures in the most current version of the Bureau's Standard Operating Procedure: Use of Portable Analyzers in Performance Tests. The permittee need only observe those sections relative to sample conditioning, analyzer range and sensitivity, response time, and calibration. The test may also be carried out using any effective procedure approved in advance by the Department. Emissions shall be expressed in ppm. Each test shall be carried out while the SRU is operating at a load representative of the load during the relevant time period. Periodic emissions tests shall be conducted at the intervals in the following schedule: First test: Six (6) months from permit issuance; Second test: Twelve (12) months from permit issuance; Third test: Twenty four (24) months from permit issuance; Fourth test: Forty eight (48) months from permit issuance; All subsequent testing shall follow at twenty-four (24) month intervals. However, the test schedule is contingent on maintaining test data that indicates compliance. If any test indicates non-compliance, the periodic emissions test sequence shall revert to the beginning of the above schedule starting with the date of the most recent test.
Other Appropriate Quality Control and Quality Assurance Measures: Initial emissions testing is required for SRU's that have not been stack tested in the ten years previous to permit issuance. SRU's equipped with CEMS shall be recertified every year in accordance with NSPS Appendix B, 40 CFR 60.
Cost Analysis: Unknown

CHAPTER IV
FUEL COMBUSTION UNITS

This chapter addresses existing monitoring requirements for the broad category of industrial boilers, turbines, and other fuel combustion units that may be subject to the backstop trading program. This category affects many different industrial facilities, and includes many different types of units, especially with respect to fuel type and unit size. The fuel type has a significant impact on monitoring. For example, EPA has generally been receptive to fuel sampling options in trading programs, but only for non-solid fuel combustion units. In addition, the possibility that small units may be subject to the trading program is an issue for selecting appropriate monitoring.

The methodology for reviewing this category began with an acknowledgment that the monitoring provisions in 40 CFR Part 75 already apply to many of the unit types in this category, and that those provisions include non-CEMS options for units that do no burn solid fuel. In addition, the OTC has applied similar monitoring to numerous industrial fuel combustion units (but for NO_x mass in place of SO_2 mass emissions). These existing monitoring programs are used as the basic benchmark in this chapter because they are designed for emissions trading programs. However, these existing monitoring programs have not applied to smaller industrial combustion units nor to pulp mill recovery furnaces. To address these units, we examined NSPS provisions and followed up with State contacts to identify any additional State-based monitoring requirements.

The results of this review are summarized in the following tables. Table IV-1 provides a brief snapshot of the primary federal and OTC monitoring requirements that apply, and Tables IV-2 through IV-6 provide a more detailed overview of the requirements in Table IV-1 that potentially could be used as part of an SO_2 trading program. Tables IV-7 through IV-9 provide examples of SO_2 mass monitoring systems from Oregon that appear to be potential candidates as well. Note that the SCAQMD also has SO_2 mass monitoring under its RECLAIM program. Because of the closeness between the basic elements of those provisions and EPA's Part 75 program, we have not summarized the South Coast provisions separately.

We have included some approximate cost information for many of the basic monitoring approaches. Preliminary cost estimates are provided for Part 75 CEMS and fuel sampling/fuel flow monitoring methodologies based on previous Part 75 monitoring cost analysis. We also used the EPA, CEMS Cost Model Version 3.0 and User Manual, 1998.

Table IV-1
Summary of Part 75, OTC and NSPS Monitoring Methods

<table>
<tr><th rowspan="2">Primary Source Category</th><th rowspan="2">Source Types</th><th colspan="3">Applicable Federal/Trading Program Monitoring Options</th></tr>
<tr><th>PART 75 Regulations</th><th>OTC NO_x Budget Program</th><th>NSPS</th></tr>
<tr><td>Refineries</td><td>Fuel Gas Combustion Unit
- Boilers
- Process Heaters</td><td rowspan="3">! SO_2 and Flow CEMS (all fuel types). [See Table IV-2]

! Fuel sampling and analysis for sulfur and gross calorific value (GCV), and fuel flow monitoring. Sampling and analysis schedule based on maximum sulfur content and sulfur/GCV variability (oil and gas units only). Use assumed sulfur default value for pipeline natural gas. [See Table IV-3]

! Units with low mass emissions (25 tons/year SO_2) can use default SO_2 emission factors combined with unit's max. rated heat input or long term fuel flow monitoring (gas and oil fired units only) . [See Table IV-4]</td><td rowspan="3">Generally the same as Part 75, except used for NO_x mass monitoring. See approved fuel sampling approaches for GCV of process gas. Units that had been subject to the OTC program monitoring requirements now must meet Part 75, Subpart H requirements as part of the NO_x SIP Call. Note that this requirement extends to cement kilns.</td><td>SO_2 and O_2 CEMS (ppm); or

Fuel gas H_2S monitoring (ppm or gr/dscf).

[Part 60, Subpart J] [See Table IV-6]</td></tr>
<tr><td>Industrial Boilers (including cogenerators)</td><td>Boilers - fossil-fuel fired
- coal, solid fuel
- natural gas
- process gas
- fuel oil</td><td rowspan="2">SO_2 and O_2 or CO_2 CEMS (lb/MMBtu);

Daily coal or oil sampling and analysis for sulfur and heat content; or

Daily stack testing (lb/MMBtu). Note: May use as received tank sampling in place of daily sampling for oil.

For small units or units burning low sulfur oil, can use fuel supplier certification. (lb/MMBtu).

[Part 60 Subparts D, Da, Db, Dc] [See Table IV-5]</td></tr>
<tr><td rowspan="2">Pulp and Paper</td><td>Boilers - fossil-fuel fired</td></tr>
<tr><td>Recovery Boilers</td><td>Not directly applicable.</td><td>Not directly applicable.</td><td>TRS CEMS
(ppm)
[Part 60 Subpart BB]</td></tr>
</table>

Table IV-2
Part 75 CEMS Methodology

<table>
<tr><td>Primary Source Category: Refineries, Industrial Boilers, Pulp and Paper</td></tr>
<tr><td>Source Type: Boilers/Process Heaters/Recovery Furnaces</td></tr>
<tr><td>Emission Measurement/Quantification System: Requirements are in 40 CFR 75.10 and 75.11.

! SO_2 and Flow CEMS (may also use a diluent CEMS if heat input is also required)
! The CEMS includes a Data Acquisition and Handling System (DAHS) for electronic processing of measurement data.
! Equipment and performance specifications are in Part 75, Appendix A.</td></tr>
<tr><td>Averaging Times: Hourly (measurement recorded at least every 15 minutes) - Sec. 75.10(d).</td></tr>
<tr><td>Consideration of Batch, Seasonal, and Cyclical Operations: The frequency of quality assurance testing (RATAs, linearity, flow to load, differential pressure flow monitor leak checks) is based on the number of operating hours in a quarter (Part 75, Appendix B).</td></tr>
<tr><td>Calculations Used to Determine Quarterly and Annual Mass Emissions: Calculations are specified in Part 75, Appendix F, Sec. 2:

! Annual Mass Emissions = Sum of Quarterly Mass Emissions
! Quarterly Mass Emissions = Sum of Hourly Emissions
! Hourly Emissions = (hourly SO_2 concentration) x (hourly flow) x (unit conversion factor)</td></tr>
<tr><td>Procedures for Addressing Missing and Invalid Data: Part 75, Subpart D requires sources to account for emissions during periods when there are no valid data (missing data periods) due to the monitor not operating or operating out of control. The missing data algorithms in Table 1, Sec. 75.33, become increasingly conservative as monitor downtime increases, and are based on previous monitoring data. There are also optional missing data procedures for units using control equipment which rely on control equipment parameter monitoring (Sec. 75.34).</td></tr>
<tr><td>Recordkeeping and Reporting Requirements:

<u>Recordkeeping</u>:

! Monitoring plan which includes basic unit identification information and monitoring methodology (Sec. 75.53).
! Quality Assurance/Quality Control Plan and Maintenance Log (Sec. 75.21 and Appendix B)
! Certification (including recertification) and quality assurance test results (Sec. 75.59)
! Hourly CEMS data including unit operating time, SO_2 concentration, flow, SO_2 mass rate, percent monitor data availability, and SO_2 method of determination (Sec. 75.57).

<u>Reporting</u>:

! Initial certification application (includes monitoring plan and initial certification test results) (Secs. 75.62 and 63).
! Quarterly reporting of hourly CEMS data, quality assurance test results, recertification tests, and summary of quarterly and year to date emissions (Sec. 75.64).</td></tr>
</table>

Initial Performance Testing: Part 75 initial certification testing is outlined in Sec. 75.20 and Appendix A, Sec. 6: ! 7-day calibration error test for each monitor ! Linearity check for each pollutant concentration monitor ! Relative Accuracy Test Audit (RATA) for each monitor ! Bias test for each SO_2 pollutant concentration monitor and flow monitor ! Cycle time test for each SO_2 pollutant concentration monitor ! Daily interference test for flow monitors ! DAHS testing
Periodic Calibration: Part 75, Appendix B: ! Daily calibration error tests are required for the gas CEMS. ! Daily interference test for flow CEMS.
Audits: Part 75, Appendix B: ! Quarterly linearity tests for SO_2 CEMS ! Quarterly flow-to-load evaluations for flow monitor values. ! Semi-annual or annual RATAs for SO_2 and flow CEMS. ! Annual leak check for differential pressure flow CEMS.
Other Appropriate Quality Control and Quality Assurance Measures: Recertification (includes quality assurance testing) is required for a replacement, modification, or change that may significantly affect the CEM's ability to accurately measure monitored parameters (Sec. 75.20(b)).
Cost Analysis: a. Installed Capital Cost: $124,000 to $192,000 with median of $138,000 (Part 75 CEM Cost Study (1999)). This is for a Part 75 NO_x\Diluent\Flow CEMS, but SO_2 analyzer cost should be comparable (OAQPS CEM Cost Model Manual - $12,500 for SO_2 analyzer versus $10,440 for NO_x analyzer), or $165,000 for SO_2/Flow CEMS (OAQPS CEM Cost Model). b. Direct Operating Cost: $55,500 for a complete Part 75 CEMS setup, which includes both SO_2, NO_x, Diluent, and Flow CEMS (U.S. EPA Title IV ICR, 2002, labor costs adjusted to 1998 dollars), or $34,800 for SO_2/Flow CEMS (OAQPS CEM Cost Model). c. Total Annualized Cost: $75,100 (Part 75 CEM Cost Study (1999) and Part 75 ICR),or $58,400 (OAQPS CEM Cost Model). d. Equipment Life: 5 - 20 years, median - 10 years (Part 75 CEM Cost Study (1999)) e. Year Dollars: 1998 f. Discount Rate: 7%

Table IV-3
Part 75 Appendix D Fuel Sampling/Flow Method for Oil and Gas Fired Units

Primary Source Category: Refineries, Industrial Boilers, Pulp and Paper
Source Type: Gas and Oil Fired Boilers/Process Heaters.
Emission Measurement/Quantification System: 40 CFR Part 75, Appendix D. ! Fuel flow monitoring with certified flow meter, and ! Fuel sampling and analysis to determine SO_2 emission factor, and fuel heat input. ! Oil sampling and analysis for sulfur content, density, and gross caloric value (GCV) using American Society for Testing and Materials (ASTM) standard methods. Sampling alternatives (Appendix D, Sec 2.2, Table D-4) include: after each delivery, from the fuel storage tank, daily flow proportional sampling, and daily as fired sampling. ! Gaseous sampling and analysis for sulfur content and GCV using ASTM standard methods varies by fuel sulfur content and sulfur/GCV variability. Sulfur content analysis is not required for pipeline natural gas if supplier contract or tariff verifies a total sulfur content not greater than 0.5 gr/100 scf, or not greater than 20.0 gr/100cf for natural gas. Required sulfur analysis sampling frequency can be hourly, daily, annually, or by shipment. Required GCV analysis sampling frequency can be hourly, daily, monthly or by shipment. (Appendix D, Sec 2.3 Table D-5) ! Must use a Data Acquisition and Handling System (DAHS) for electronic processing of measurement data. ! Equipment and performance specifications for fuel flow monitors are in Part 75, Appendix D. The DAHS specifications are in Part 75, Appendix A, Sec. 4.
Averaging Times: Hourly
Consideration of Batch, Seasonal, and Cyclical Operations: The frequency of quality assurance testing is based on quarterly operating hours (Part 75, Appendix D, Sec. 2.1.6.)
Calculations Used to Determine Quarterly and Annual Mass Emissions: Calculations are specified in Part 75, Appendix D, Sec. 2.3: ! Annual Mass Emissions = Sum of Quarterly Mass Emissions ! Quarterly Mass Emissions = Sum of Hourly Emissions ! Hourly Emissions = SO_2 emission factor (lb/MMBtu) x hourly heat input (MMBtu), or $\left(\frac{2.0}{7000}\right)$ x fuel flow rate (scf/hr) x sulfur content (gr/scf) ! The SO_2 emission factor may be a default factor of 0.0006 lb/MMBtu, if using pipeline natural gas. If using natural gas, can use contract/tariff value as default. If using other gas, can calculate a default value if low sulfur variability, or use as sampled value based on hourly, daily, or as shipped basis.
Procedures for Addressing Missing and Invalid Data: Part 75, Subpart D requires sources to account for emissions during periods when there are no valid data (missing data periods) due to the monitor not operating or operating out of control: ! Missing fuel analysis data - use default values in Appendix D, Sec. 2.4.1 Table D-6. ! Missing fuel flow rate (single fuel) - load based using data from previous 720 monitored hours, or if load data is not appropriate for the unit, use the average flow rate over the previous 720 hours for the same fuel. (Appendix D, Sec. 2.4.2). ! Missing fuel flow rate (multiple fuels) - Similar to the single fuel requirements, except that the previous 720 hours when burning multiple fuels are used. (Appendix D, Sec. 2.4.2).

Recordkeeping and Reporting Requirements: <u>Recordkeeping</u>: ! Monitoring plan which includes basic unit identification information and monitoring methodology (Sec. 75.53). ! Quality Assurance/Quality Control Plan and Maintenance Log (Sec. 75.21 and Appendix B). ! Certification (including recertification) and quality assurance test results (Sec. 75.59). ! Hourly data including unit operating time, load, type of fuel, fuel flow, fuel GCV, oil density if required, heat input rate, fuel sulfur content, SO_2 mass rate, percent monitor data availability, and SO_2 method of determination (Sec. 75.57). <u>Reporting</u>: ! Initial certification application (includes monitoring plan and initial certification test results) (Secs. 75.62 and 63). ! Quarterly reporting of hourly data, quality assurance test results, recertification tests, and summary of quarterly and year to date emissions (Sec. 75.64).
Initial Performance Testing: ! Fuel flow meter accuracy testing (Appendix D, Sec. 2.1.5). Meters used for commercial billing are exempt (Part 75, Appendix D, Sec. 2.1.4.2). ! DAHS testing (Sec. 75.20 and Appendix A, Sec. 6).
Periodic Calibration: See Audits.
Audits: Quality assurance requirements do not apply to fuel flow meters used for billing purposes (Part 75, Appendix D, Sec. 2.1.4.2). Part 75, Appendix D, Sec. 2.1.6: ! Fuel flowmeter accuracy test performed every 4 operating quarter which may be extended up to 20 operating quarters. ! Primary element visual inspection performed every 12 calendar quarters. Part 75, Appendix D, Sec. 2.1.7: Optional fuel flow to load test may be performed in lieu of fuel flowmeter accuracy test.
Other Appropriate Quality Control and Quality Assurance Measures: Recertification (includes quality assurance testing) is required for a replacement, modification, or change that may significantly affect the monitoring system ability to accurately measure monitored parameters (Sec. 75.20(b)).

Cost Analysis:	
a. Capital Cost:	$3,200 - $10,000, median $7,800 for oil flow meter $1,500 - $6,400, median $2,900 for gas flow meter Installation costs are not included (Part 75 CEM Cost Study (1999)).
b. Direct Operating Cost:	$750 for inspection, $200- $2,000 for in-line calibration (Part 75 CEM Cost Study (1999)).
c. Total Annualized Cost:	$250 - $350 per manual oil sample (utility group (Class of '85) comments on Part 75). Number of events/year dependent on unit characteristics. No information on costs for continuous sampling approaches for high sulfur variability gaseous fuel (such as using a gas chromatograph).
d. Equipment Life:	Not available
e. Year Dollars:	1998
f. Discount Rate:	7%

Table IV-4
Part 75 Low Mass Emissions Unit Methodology for Oil and Gas Fired Units

Primary Source Category: Refineries, Industrial Boilers, Pulp and Paper
Source Type: Gas and oil fired boilers/process heaters, with annual SO_2 emissions less than or equal to 25 tons. To qualify, units burning a gaseous fuel other than natural gas also must meet the default emission rate qualifications in Part 75, Appendix D, Sec. 2.3.6(b). This qualification procedure requires a 720 hour sampling test to show low fuel sulfur variability (maximum standard deviation of 5.0 gr/100 scf) or low sulfur content (maximum of 20 gr/100 scf).
Emission Measurement/Quantification System: Low Mass Emission (LME) Provisions in 40 CFR 75.19(c). ! For each hour, record unit operating time, type of fuel burned, and if using the long term fuel flow method - load or steam production. Units using the long term fuel flow method also measure the amount of fuel burned each quarter (measured using billing records, tank level measurement, or Appendix D fuel flow monitors). ! Hourly SO_2 emission rate based on default values for natural gas and fuel oil in Table LM-1, or calculated default values (Equation D-1) for gaseous fuels other than natural gas. ! Hourly heat input may be based on the unit's maximum rated heat input times operating time, or long term fuel monitoring, combined with sampled or default fuel gross caloric value (GCV) and fuel density values). Hourly apportionment of the long term fuel use is apportioned based on hourly load as a fraction of the total quarterly load.
Averaging Times: Hourly, Quarterly
Consideration of Batch, Seasonal, and Cyclical Operations: Not Applicable
Calculations Used to Determine Quarterly and Annual Mass Emissions: Sec. 75.19(c)(3) and (4): ! Annual Mass Emissions = Sum of Quarterly Mass Emissions. ! Quarterly Mass Emissions = Sum of Hourly Emissions. ! Hourly Emissions = SO_2 Default Emission Factor x Hourly Heat Input. ! Hourly Heat Input = Maximum rated heat input capacity times operating time or apportioned based on long term heat input measurement and hourly load. ! Natural gas and fuel oil default values are provided for emission factors (lbs SO_2/MMBtu), GCV, and oil density. Other gaseous fuels have prescribed approach to determine fuel-specific defaults.
Procedures for Addressing Missing and Invalid Data: Not applicable.

Recordkeeping and Reporting Requirements:

Recordkeeping:

- Monitoring plan which includes basic unit identification information and monitoring methodology (Sec. 75.53).
- Hourly records of unit operating time, fuel burned, and unit load if using long term fuel flow monitoring (Sec. 75.19(c)(2)).
- Quarterly long term fuel monitoring results for units using that heat input option (Sec. 75.19(e)).
- Sampling and analysis results for fuel sulfur content, GCV, and density if required (Sec. 75.19(e)).

Reporting:

- Initial certification application (includes monitoring plan and LME applicability demonstration) (Secs. 75.62 and 63, Sec. 75.19a).
- Quarterly reporting of hourly operating records, and summary of quarterly and year to date emissions (also heat input and load if using long term fuel monitoring) (Sec. 75.64)

Initial Performance Testing: Initial LME Applicability Demonstration, Sec. 75.19(a):

- Three years of emission data are required to demonstrate that annual SO_2 emissions are not greater than 25 tons, or
- If three years of data does not exist (or if there is a change in operations through permit limits), the demonstration may be based on projected annual emissions.
- Units burning gaseous fuels other than natural gas must demonstrate sulfur content and variability meets the default equation qualifications in Part 75, Appendix D, Sec. 2.3.6(b).
- Also, units using Part 75, Appendix D fuel flow monitors for long term fuel flow monitoring must meet Part 75, Appendix D, Sec. 2.1.5 certification requirements (initial fuel flow meter accuracy test). Billing meters are exempt from certification requirements.

Periodic Calibration: Units using fuel flow monitors for long term fuel flow monitoring must perform periodic calibration tests and inspections every twelve operating quarters (frequency may be extended to every twenty operating quarters). These requirements are in Part 75, Appendix D, Sec. 2.1.6.

Audits: Annual LME applicability demonstration in Sec 75.19(b).

Other Appropriate Quality Control and Quality Assurance Measures: Not applicable.

Cost Analysis:

a. Installed Capital Cost:	N/A
b. Direct Operating Cost:	Labor burdens for recordkeeping/reporting will apply. EPA estimates 16 hours per year ($899) above and beyond customary business practices (2002 Acid Rain Program ICR).
c. Total Annualized Cost:	Labor burdens for recordkeeping/reporting will apply. EPA estimates 16 hours per year ($899) above and beyond customary business practices (2002 Acid Rain Program ICR).
d. Equipment Life:	N/A
e. Year Dollars:	2001 (for labor rates)
f. Discount Rate:	N/A

Table IV-5
NSPS Monitoring Methodology for Coal and Oil Fired Industrial Boilers

Primary Source Category: Industrial Boilers
Source Type: Coal or Oil Fired Industrial Boilers (10 MMBtu/hr to 250 MMBtu/hr) 40 CFR 60 Subparts Db and Dc - New Source Performance Standards.
Emission Measurement/Quantification System: Monitoring requirements vary based on fuel type and boiler size. Alternatives described below may be used for all units except where specified 1) SO_2 and diluent CEMS; or 2) Daily Method 6 stack test; or 3) Fuel sampling/analysis (as fired sampling unless unit burns oil and has a maximum rated heat input $\leq$ 100 MMBtu/hr; in that case sampling may be performed each time the fuel tank is filled); or 4) Supplier fuel receipts (oil fired boilers burning oil with S content $\leq$ 0.5%, or oil fired boiler with maximum rated heat input $\leq$ 100 MMBtu/hr; Coal fired boilers with maximum rated heat input $\leq$ 30 MMBtu/hr).
Averaging Times: ! 30 day rolling averages, ! Daily averages, ! CEMS hourly average based on 15-minute sampling intervals.
Consideration of Batch, Seasonal, and Cyclical Operations: Units with infrequent operation (capacity factor of 10% or less on subject fuel) may be eligible for alternative monitoring methods.
Calculations Used to Determine Quarterly and Annual Mass Emissions: None
Procedures for Addressing Missing and Invalid Data: Emission data must be obtained for at least 75% of operating hours in at least 22 out of 30 successive days by the monitoring methods described above.
Recordkeeping and Reporting Requirements: Sec. 60.49b and Sec. 60.48c. ! Records of measurements and calculations must be retained 2 years. ! Submit initial performance test results and summary or excess emission reports semi-annually.
Initial Performance Testing: Performance Specification 2 for SO_2 CEMS (7 day calibration drift and RATA)
Periodic Calibration: Daily calibration drift test (40 CFR Part 60, Appendix F). The monitoring devices must also be calibrated at least annually according to manufacturers specifications.

Audits: ! Conduct a performance evaluation of the CEMS during or within 30 days any performance test required under §60.8. ! Conduct CEMS audits once per quarter (40 CFR Part 60, Appendix F) - Relative Accuracy Test Audit (RATA) must be conducted at least once every four calendar quarters. - Cylinder Gas Audit (CGA), if applicable, may be conducted in three of four calendar quarters - Relative Accuracy Audit (RAA) may be conducted three of four calendar quarters
Other Appropriate Quality Control and Quality Assurance Measures: ! Preventive maintenance of CEMS (including spare parts inventory). ! QC for data recording, calculations, and reporting. ! Program of corrective action for malfunctioning CEMS.
Cost Analysis: See OAQPS CEM Cost Model figures in Table IV-2 for SO_2/flow. Note that NSPS does not address flow monitoring.

Table IV-6
NSPS Monitoring Methodology for Refinery Boilers/Process Heaters

Primary Source Category: Refineries
Source Type: Fuel Gas Combustion Devices (Boilers/Process Heaters) 40 CFR 60 Subpart J - New Source Performance Standard
Emission Measurement/Quantification System: To demonstrate compliance with fuel gas H_2S concentration limit in Sec 60.104(a)(1): 1) SO_2 and O_2 CEMS (ppm), or 2) Continuous monitoring of H_2S concentration in the fuel gas (gr/dscf or mg/dscm).
Averaging Times: ! Rolling 3-hour averages ! Hourly average based on 15-minute sampling intervals
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: None
Procedures for Addressing Missing and Invalid Data: No procedures specified.
Recordkeeping and Reporting Requirements (Sec. 60.7): ! Records of measurements and calculations must be retained 2 years. ! Submit summary or excess emission reports semi-annually.
Initial Performance Testing: ! Performance Specification 2 for SO_2 CEMS (7 day calibration drift and RATA) ! Performance Specification 7 for the H_2S CEMS (7 day calibration drift and RATA)
Periodic Calibration: Daily calibration drift test. The monitoring devices must also be calibrated at least annually according to manufacturers specifications.
Audits: ! Conduct a performance evaluation of the CEMS during or within 30 days any performance test required under §60.8 ! Conduct CEMS audits once per quarter - Relative Accuracy Test Audit (RATA) must be conducted at least once every four calendar quarters. - Cylinder Gas Audit (CGA), if applicable, may be conducted in three of four calendar quarters - Relative Accuracy Audit (RAA) may be conducted three of four calendar quarters
Other Appropriate Quality Control and Quality Assurance Measures: ! Preventive maintenance of CEMS (including spare parts inventory). ! QC for data recording, calculations, and reporting. ! Program of corrective action for malfunctioning CEMS.
Cost Analysis: See Table IV-2 for OAQPS CEM Cost Model figures for SO_2/flow CEMS. Note that NSPS Subpart 3 does not address flow monitoring.

Table IV-7
State of Oregon Coal-fired Boiler CEMS/Flow Estimation Example

Primary Source Category: Beet Sugar Manufacturing
Source Type: Coal Fired Boiler
Emission Measurement/Quantification System: Continuous Emission Monitoring System (based on NSPS requirement) and steam data/emission factor for conversion to mass emissions.
Averaging Times: Hourly averages and monthly average of the hourly averages
Consideration of Batch, Seasonal, and Cyclical Operations: Yes, this is a seasonal operation and the CEMS reporting and QA/QC requirements are based on actual operating hours.
Calculations Used to Determine Quarterly and Annual Mass Emissions: Mass emissions determinations to determine compliance with the plant site emission limit (PSEL) is performed as follows: $P_{eu} \times EF_{eu}/2000$ P_{eu} = 1000 lbs steam per year EF_{eu} = 0.100 lb SO_2 /1000 lbs steam
Procedures for Addressing Missing and Invalid Data: None
Recordkeeping and Reporting Requirements: ! The permittee shall maintain a minimum valid data availability of 90% of boiler operating hours, on a seasonal basis. ! Monitoring system performance reports shall be submitted to the Department semi-annually. ! The permittee shall maintain a CMS log as required by the Department continuous monitoring manual. ! Semi-annual compliance certifications
Initial Performance Testing: No performance testing requirements of emission unit within current permit that exceed the CEMS auditing procedures (RATA)
Periodic Calibration: Daily calibration
Audits: Quarterly audits, either CGA or RAA. Once every four quarters of operation a RATA is required.
Other Appropriate Quality Control and Quality Assurance Measures: Mandatory submittal and periodic review of CEM quality assurance plan and standard operating procedures manual.
Cost Analysis: Unknown

Table IV-8
State of Oregon Industrial Boiler Fuel-based Estimation Method

Primary Source Category: Kraft Pulp Mill
Source Type: Power Boiler (oil/ natural gas fired)
Emission Measurement/Quantification System: Material Balance Approach
Averaging Times: Not Applicable
Consideration of Batch, Seasonal, and Cyclical Operations: No consideration for batch, seasonal & cyclical operations. There are considerations for switching between types of fuels and for testing oil guns.
Calculations Used to Determine Quarterly and Annual Mass Emissions: Material Balance Calculation: $E = 2 \times F \times S$ E=emissions of SO_2 S=sulfur content, % wt. F=Fuel use (lbs/month or tons/yr)
Procedures for Addressing Missing and Invalid Data: Not Applicable
Recordkeeping and Reporting Requirements: ! The permittee shall monitor and record the type and amount of fuels used each day. ! The permittee shall monitor and record the number of hours per year that oil is used as fuel. ! The permittee shall monitor and record the sulfur content of each batch of fuel oil received. ! Semi-annual monitoring report requirement.
Initial Performance Testing: No performance testing requirements of emission unit within current permit.
Periodic Calibration: Not Applicable
Audits: Audit records during source inspection
Other Appropriate Quality Control and Quality Assurance Measures: None
Cost Analysis: Unknown

Table IV-9
State of Oregon Recovery Furnace CEMS/Flow Estimation Example

Primary Source Category: Unbleached Kraft Pulp Linerboard and Corrugating Medium Mill
Source Type: Recovery Furnaces
Emission Measurement/Quantification System: CEMS for TRS (as H_2S) and for SO_2
Averaging Times: TRS: Daily arithmetic averages calculated from 1-hour arithmetic averages. SO_2: Three hour block average concentration calculated from one hour arithmetic averages
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: ! TRS: Calculate emissions of total reduced sulfur [TRS/ton equivalent air dried tons pulp (ADTP)] by: - Daily average concentration - Flow rate estimated from source tests & firing rate correlation - Equivalent ADTP production ! SO_2: Calculate emissions of SO_2 by utilizing concentration from CEM and exhaust flow rate calculated from the flow rate/BLS firing rate correlation.
Procedures for Addressing Missing and Invalid Data: None, 75% data recovery on a 1-hour period and 90% data recovery for a 1-hour period required for a CMS data average to be accepted (ODEQ Continuous Monitoring Manual).
Recordkeeping and Reporting Requirements: ! The permittee shall report the following information within 30 days of the end of each calendar month: - Daily average concentration of TRS gases - Daily average emissions of TRS gases as lbs/equivalent tons of pulp processed - Three-hour average emissions of SO_2 based on all samples collected in one sampling period, expressed as ppmdv, and the exhaust flow rate during the last source test.
Initial Performance Testing: No performance testing requirements of emission unit within current permit that exceeds the CEMS auditing procedures (RATA)
Periodic Calibration: Daily Calibrations
Audits: Quarterly audits, either CGA or RAA. Once every four quarters a RATA is required.
Other Appropriate Quality Control and Quality Assurance Measures: Mandatory submittal and periodic review of CEM quality assurance plan and standard operating procedures manual.
Cost Analysis: Unknown

CHAPTER V
CATALYTIC CRACKING UNITS

Catalytic cracking units convert gas oil feed streams into fuel gas, liquified petroleum gas (LPG), high-octane gasoline, and distillate fuel through the use of a catalyst, generally in the form of fluidized particulates (fluidized catalytic cracking). The feed stream is heated in process heater and then the catalyst is added to separate the hydrocarbons. The spent catalyst is regenerated by steam stripping and burning off petroleum coke deposits. SO_2 is emitted from the process heater and during regeneration of the catalysts.

The NSPS for petroleum refineries (40 CFR 60 Subpart J) includes SO_2 standards for FCCUs. Monitoring requirements in the NSPS rule are summarized in Table V-1. There are different requirements based on the following situations; 1) source has an SO_2 control device and meets 90% reduction standard, 2) source has an SO_2 control device and meets < 50 ppm standard, 3) source has no control device, or source uses a waste-incinerator boiler. Sources with a control device must monitor SO_2 emission rates using a CEMS for SO_2 and O_2. Sources with no control device must record the sulfur content of the fresh feed, the average coke burn-off rate, and hours of operation on a daily basis. Sources with an incinerator-waste heat boiler must record fuel usage and operating hours.

There are refineries located in California, Colorado, New Mexico, Utah and Wyoming. It is unknown whether these facilities have SO_2 control devices installed on the FCCUs. Information from California's SCAQMD indicates that SO_2 and flow CEMS are required under RECLAIM for this source type. The SCAQMD uses alternative quality assurance procedures for FCCUs with low SO_2 concentrations ($\leq$5 ppm) – see SCAQMD Rule 2011, Appendix A, Attachment F. Table V-2 summarizes SCAQMD SO_2 monitoring requirements for FCCUs.

Pechan obtained information from the State of New Mexico regarding a consent decree for a refinery. In the consent decree, a CEMS for the FCCU is proposed. There are no details on specific monitoring requirements. The information obtained from New Mexico is presented in Table V-3.

Table V-1
NSPS Monitoring Requirements for Fluidized Catalytic Cracking Units

Primary Source Category: Refineries 40 CFR 60 Subpart J
Source Type: Fluid Catalytic Cracking Unit (FCCU)
Emission Measurement/Quantification System: **With an add-on control device of 90% reduction:** CEMS for SO_2 (dry, 0% O_2 ppmv) and O_2 at both the inlet and outlet of the SO_2 control device Span value: inlet is125% and outlet is 50% of the maximum estimated hourly potential SO_2 emission concentration entering the control device. Span value for O_2 monitor is 10% **With an add-on control device and emission of >= 50 ppm:** CEMS for SO_2 (dry, 0% O_2 ppmv) and O_2 at the discharge Span value: SO_2 is 50 percent of the maximum hourly potential of the control device, O_2 is 10% **Without the use of an add-on control device:** Record the average coke burn-off rate (Mg (tons) per hour) and hours of operation on a daily basis. Monitor sulfur content of fresh feed. **FCCU catalyst regenerator using incinerator-waste heat boiler:** Record fuel usage rate and hours of operation
Averaging Times: For CEMS: 1-hour averages of SO_2 and O_2 shall be computed from four or more data points equally spaced over each 1-hour period. Samples collected at inlet and/or outlet of control system or at discharge point Calculate 7-day average concentration (arithmetic mean of 1-hour averages during 7 successive days) Calculate 7-day average percent reduction for control device using 7-day averages Compliance determined on 7-day rolling average basis Provide minimum of 22 valid days of data for every 30 rolling successive calendar days CEMS downtime: provide data for a minimum of 18 hours per day in at least 22 out of 30 rolling successive calendar days. For average coke burn-off rate: One 3-hour test daily using: Method 8 modified for Moisture content and sulfur oxides (SO_x) as SO_2 Method 2 for velocity and flow Method 3 integrated sampling for gas analysis Calculate coke burn off in Mg/hr (Ton/hour) as specified in 40 CFR 60.106 (b)(3) Calculate sulfur oxides as SO_2 per Mg (ton) of coke burn off 7-day average of sulfur oxides as SO_2 per Mg (ton) of coke burn off For feed sampling: 1 fresh feed sample per 8 hours analyzed using specified ASTM method Calculate 7-day average sulfur content of fresh feed
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: None

Procedures for Addressing Missing and Invalid Data: Requires sources to account for emissions during periods when there are no valid data (missing data periods) due to the monitor not operating or operating out of control. Specifies supplemental sampling procedures for CEMS down times
Recordkeeping and Reporting Requirements: Required to submit a written report of the results of the performance evaluation within 60 days of completion. Required to submit semi-annual report: Report all data and calibrations from CEMS including daily drift and quarterly accuracy assessments under Appendix F, supplemental sampling data, quality control procedures. Report 7-day rolling averages. Report daily Method 8 test results for moisture content and sulfur dioxide as SO_2 (or alternate method), Report daily fresh feed sulfur content tests Also report date and explanation for exceedances of 7-day average, corrective action taken, any periods where 30-day data or daily monitoring requirements were not met and explanation, times hourly averages are based on manual sampling instead of CEMS, times when concentration exceeded span of CEMS, any modifications to CEMS, any changes to emissions control system while data not available.
Initial Performance Testing: Performance Specification 2 for SO_2 CEMS Reference Methods (RM) 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Conduct a minimum of nine sets of all necessary RM test runs. Correlate the CEMS and the RM test data. Calculate the mean difference between the RM and CEMS values. Calibration Drift (CD) - while unit is operating at more than 50 percent of normal load, determine the magnitude of the CD once each day (at 24-hour intervals) for 7 consecutive days. CD must not drift or deviate from the reference value of the calibration gas by more than 5 percent of the established span value for 6 out of 7 test days.
Periodic Calibration: Calibration of CEMS as specified by manufacturer Automatically check, quantify, and record the zero and span calibration drifts at least once daily. If greater than 2Xs the specified limit, the zero and span must be adjusted.

Audits: Conduct a performance evaluation of the CEMS during or within 30 days any performance test required under §60.8. Conduct CEMS audits once per quarter Relative Accuracy Test Audit (RATA) must be conducted at least once every four calendar quarters. Cylinder Gas Audit (CGA), if applicable, may be conducted in three of four calendar quarters Relative Accuracy Audit (RAA) may be conducted three of four calendar quarters Sampling and analysis methods accuracy audit
Other Appropriate Quality Control and Quality Assurance Measures: Preventive maintenance of CEMS (including spare parts inventory). QC for data recording, calculations, and reporting. Program of corrective action for malfunctioning CEMS.
Cost Analysis: EPA estimated that cost for CEMs for the extractive analyzer system would be $69,300 (1984 dollars) including installation and data acquisition system (DAS), $46,200 without it. The agency obtained cost data by contacting vendors and operators and found that “the worst-case” cost for an SO_2/diluent extractive system varied from 43,000 to $100,000 (1984 dollars). This cost included additional cost for longer sample lines, corrosion-resistant probes, probe backflush systems, and computer data acquisition systems capable of generating emission reports. Worst-case installation costs ranged from $2,000 to $80,000. Total worst-case costs for an extractive analyzer would be from $45,000 to $180,000 (including DAS and installation). Best case costs for an extractive analyzer system including installation, ranged from $15,400 to $86,000. The across the stack CEMS for an SO_2/diluent CEMS including a DAS to range from $44,000 to $96,000 in a worst case scenario with installation cost varying from $2,000 to $80,000. Assuming a DAS cost of $23,100, the total worst case cost without a DAS would be from $22,900 to $153,000. Best case scenario costs ranged from $34,000 to $60,000 per analyzer. The annual maintenance costs estimated were $11,000 for either an extractive or across the stack CEMS.

Table V-2
FCCU Monitoring Requirements for SCAQMD Rule 1105 and Rule 2011

Primary Source Category: Refineries

Source Type: Fluidized Catalytic Cracking Units (FCCUs)

Emission Measurement/Quantification System:

Must install, calibrate, maintain, and operate an approved CEMS or Alternative Monitoring System (AMS)
CEMS/AMS must measure:

a. Sulfur oxide concentrations discharged from equipment,
b. Oxygen concentrations, at sulfur oxide monitoring location (if required for stack gas flow rate)
c. Stack gas volumetric flow rate using an in-stack flow meter or an approved alternate method.
d. Fuel gas flow rate and sulfur content, if the CEMS uses these to determine SO_x emissions.
e. Variables in table

Must measure and record at least once per shift other data necessary for calculating emissions.

EQUIPMENT	MEASURED VARIABLES
FCCUs	1. Stack SO_x concentration and exhaust flow rate;
	2. CEMS Status code;
	3. Feed rate.
FCCUs with feed hydrodesulfurization	All variables identified for FCCUs.
FCCUs with SO_x reducing catalyst	All variables identified for FCCUs; and
	4. Type and amount of catalyst used.
FCCUs with wet flue gas desulfurization (e.g., slurry of $Ca(OH)_2/CaCO_3$ or $NaOH/Na_2CO_3$)	All variables identified for FCCUs; and
	4. Scrubber solution injection rate.
FCCUs with dry flue gas desulfurization (e.g., dried slurry of $Ca(OH)_2/CaCO_3$ or $NaOH/Na_2CO_3$)	All variables identified for FCCUs; and
	4. Scrubber solution injection rate

Averaging Times:

1-hour average equally computed based on four valid 15-minute average emission data points equally spaced over each 1-hour period. (Only 2 required during CEMS maintenance activities)

Consideration of Batch, Seasonal, and Cyclical Operations: None

Calculations Used to Determine Quarterly and Annual Mass Emissions:

$$e_i = a_i \times c_i \times 1.662 \times 10^{-7}$$

Sulfur oxide mass emissions in units of lb/hour:

where: e_i = Mass emissions of sulfur oxides (lb/hr),
a_i = Stack gas concentration of sulfur oxide (ppmv), and
c_i = Stack gas volumetric flow rate (scfh).

The daily emissions of sulfur oxides for each affected SO_x source:

$$G = \sum_{k=1}^{n} E_k + \sum_{m=1}^{p} E_m$$

where:
G = Daily emissions of sulfur oxide (lb/day),
E_k = Hourly average emission rate using CEMS (lb/hr)
E_m = Hourly average emission rate of sulfur oxides using substitute data (lb/hr),
n = Number of hours of valid data from CEMS coinciding with the operating hours
p = Number of hours using substitute data when the source is operating; and
m = Number of operating hours of the source during the day.

All measurements for concentrations and stack gas flow rates, and selection of F factor shall be made on a consistent wet or dry basis.

Must obtain approval for all formulas necessary to calculate the mass emission rates of SO_x from the regenerator per thousand barrels of feed.

Procedures for Addressing Missing and Invalid Data:

Emission rate data may be obtained using District Methods 6.1 or 100.1 (for SO_x) in conjunction with District Methods 1.1, 2.1, 3.1, and 4.1 or by using District Methods 6.1 or 100.1 in conjunction with District Method 3.1 and EPA Method 19.

Emission rate data may also be obtained using District Methods 307-91 or ASTM Method D1072-90, Standard Test for Total Sulfur in Fuel Gases (for sulfur content in the fuel gas) in conjunction with the fuel gas flow rate.

May use the procedure in 40 CFR Part 75 Subpart D if the relative accuracy of the pollutant analyzer and flow measurement system during the last CEMS certification test and/or RATA are both less than 10%.

Calculate on a daily basis the percent data availability of analyzer then substitute data calculated as:
a. if availability is >= 95% and missing data is:
< 24 hours: 1N Procedure in Attachment A or E(1)(b)(ii), or
> 24 hours: max hourly concentration recorded for previous 30 days.
b. if availability is >= 90% and missing data is:
< 3 hours: average of concentration for the hour before and after missing data period,
> 3 hours: max hourly concentration recorded for previous 30 days, or
> 24 hours: max concentration recorded for previous 365 days
c. if availability is > 90%: highest hourly concentration recorded during the service of the CEMS

Recordkeeping and Reporting Requirements: 1. Total daily SO_x mass emissions from each source, 2. Daily status codes, 3. Daily electronic transmittal of remote terminal unit (RTU) data, 4. Monthly submittal of daily records of SO_x emission rates per thousand barrels of feed, 5. Monthly aggregated SO_x emissions, 6. Semi-annual and CEMS certification tests 7. Must submit a CEMS plan for approval CEMS data shall be recorded by: 1) RTU and 2) strip chart or alternative electronic recorder. The strip chart recorder or alternative shall receive data independent of the RTU and serve as an independent tool for verifying data. Must measure and record 1) variables necessary for the alternate gas volumetric flow rate method, 2) measurements in Table 2-A and 3) other measured data to support calculations. Recorded data shall be readily accessible upon request. Must maintain records of measurements, tests, calibrations audits and QA data for 3 years. Keep a written record of QA and audit procedures.
Initial Performance Testing: Same requirements as audits
Periodic Calibration: CEMS design shall allow determination of calibration drift. Requires zero and span calibration checks, and zero and span adjustments. Perform any calibration error test procedures specific to the CEMS. Attachment C Quality Assurance And Quality Control Procedures: 1. Test, record, and compute the calibration error of each monitor at least once per operating day. Perform the daily calibration error test according to the procedure in Chapter 2, Subdivision B, Paragraph 1, Subparagraph a, Clause ii of this Attachment. 2. Test, compute, and record the calibration error of each stack flow monitor at least once per 14 calendar days. Perform daily flow monitor interference checks. All transducers and transmitters installed on stack flow monitors must be calibrated every two operating calendar quarters.
Audits: Requires semi-annual CEMS certification test Meet specifications in 40 CFR Part 60, Appendix B, Performance Specification 2, Section 8 and Appendix A Attachment B Bias Test of this rule. Minimum of nine sets of tests conducted. Specifies alternate procedures. 1. Monitors and Analyzers: relative accuracy of >= 20% of the mean value of the reference method test data. 2. Volumetric flow measurement system: relative accuracy of >= 15% of the mean value of the reference method test data. Must perform study to determine the acceptability of the potential flow monitor location and to determine the number and location of flow sampling points. 3. Must demonstrate the absence of stratification (difference between highest and lowest concentration divided by average concentration is >10%.
Other Appropriate Quality Control and Quality Assurance Measures: None
Cost Analysis: Not Available

Table V-3
Monitoring Requirements for Fluidized Catalytic Cracking Units in the State of New Mexico

Primary Source Category: Refinery/New Mexico
Source Type: Catalytic Cracking Units
Emission Measurement/Quantification System: A CEMS is proposed in a consent decree for an FCCU at a refinery in New Mexico.
Averaging Times: TBD.
Consideration of Batch, Seasonal, and Cyclical Operations: None.
Calculations Used to Determine Quarterly and Annual Mass Emissions: TBD.
Procedures for Addressing Missing and Invalid Data: TBD.
Recordkeeping and Reporting Requirements: Records in accordance with 40 CFR Subpart J 60.107.
Initial Performance Testing: Required for new units.
Periodic Calibration: TBD. In accordance with 40 CFR Subpart J 60.105 Monitoring of emissions and operations.
Audits: TBD. In accordance with 40 CFR Subpart J 60.105 Monitoring of emissions and operations.
Other Appropriate Quality Control and Quality Assurance Measures: TBD.
Cost Analysis: Unknown

CHAPTER VI
FLARES

Flaring is an air pollution control technology employed at refineries, natural gas processing plants, and oil and gas production facilities to dispose of waste gas during process upsets and emergencies. SO_2 emissions from flaring result from burning waste gas which contains sulfur. The amount of SO_2 emitted during flaring is a function of the waste gas flow rate and sulfur content. The sulfur content of the flaring gas can vary widely depending on the type of process which generates the waste gas.

There are no Federal regulations that apply to SO_2 monitoring of flares. However, recent consent decrees affecting some western refineries require SO_2 emissions monitoring for certain types of flaring activity. For acid gas flaring, hydrocarbon flaring or tail gas incidents, flow meters and periodic measurement of H_2S concentration is required. If operating the flare as a fuel gas combustion device, the source must monitor H_2S in accordance with fuel gas combustion devices subject to 40 CFR § 60.104, which requires a CEMS for SO_2 and O_2, or a CEMS for H_2S. Table VI-1 summarizes the monitoring requirements for flaring activities from these consent decrees.

Summaries of New Mexico monitoring requirements for flares at refineries and natural gas processing plants are provided in Table VI-2 and Table VI-3, respectively. New Mexico requires monitoring for acid gas, inlet plant gas, and fuel gas flow and the concentration of H_2S in the acid gas and inlet plant gas. SO_2 emissions are then calculated from specified formulas.

SCAQMD does not require SO_2 monitoring of flares, since they are *not* covered by RECLAIM. There is a district rule (Rule 1118) for flare emissions. Currently SCAQMD is gathering information on flare emissions during episodes by sampling the gas using SILCO coated canisters. SILCO is a Restek trade name. Gas flow to the flares are measured using ultrasonic flow monitors, apparently to deal with the high turndown ratios.

Table VI-1
Monitoring Requirements for Flares at Refineries from Consent Decrees

Primary Source Category: Refineries Consent Decrees
Source Type: Flares
Emission Measurement/Quantification System: **For acid gas flaring, hydrocarbon flaring or tail gas incidents:** Flow meters installed on all acid gas or hydrocarbon lines to the refinery flares, or other reliable flow parameters should be measured; H_2S concentration ("ConcH_2S") shall be determined from the sulfur recovery plant feed gas analyzer, from knowledge of the sulfur content of the process gas being flared or by direct measurement (Tutwiler, draeger tube) **If operating the flare as a fuel gas combustion device:** Monitoring H_2S in accordance with fuel gas combustion devices subject to 40 CFR § 60.104(a)(1) CEMS for SO_2 (dry basis, zero percent excess air) emissions into the atmosphere and O_2 for correcting the data for excess air. Span value: 50 ppm SO_2 and 25 percent O_2 or CEMS for H_2S (dry basis) in fuel gases before being burned in any fuel gas combustion device. Span value: 425 mg/dscm H_2S. or May use an approved alternative monitoring method *(See summary for fuel gas combustion units at Refineries for additional information)*
Averaging Times: None specified in consent decrees for flow meters or H_2S measurement
Consideration of Batch, Seasonal, and Cyclical Operations: SO_2 emissions resulting from a flaring incident that is comprised of intermittent flaring; the quantity of SO_2 emitted shall be equal to the sum of the quantities of SO_2 flared during each such period of intermittent flaring.
Calculations Used to Determine Quarterly and Annual Mass Emissions: SO_2 emissions resulting from Flaring shall be calculated by the following formula: Tons of SO_2 = [FR][TD][ConcH_2S][8.44 x 10-5]. ER = Emission Rate in pounds of SO_2 per hour FR = Average Flow Rate to Flaring Device(s) during Flaring, in standard cubic feet per hour TD = Total Duration of Flaring in hours ConcH_2S = Average Concentration of Hydrogen Sulfide in gas during Flaring (or immediately prior to Flaring if all gas is being flared) expressed as a volume fraction (scf H_2S/scf gas) 8.44 x 10-5 = [lb mole H_2S/379 scf H_2S][64 lbs SO_2/lb mole H_2S][Ton/2000 lbs] If the Tail Gas Incident is a event exceeding the 250 ppmvd (NSPS J limit), from a monitored Sulfur Recovery Plant incinerator, then specified formula applies.

Procedures for Addressing Missing and Invalid Data: Missing data point(s) shall be estimated according to best engineering judgment or other monitoring data and a report submitted, which includes data used in the calculation and an explanation of the basis for any estimates of missing data.
Recordkeeping and Reporting Requirements: None specified
Initial Performance Testing: None specified
Periodic Calibration: None specified
Audits: None specified
Other Appropriate Quality Control and Quality Assurance Measures: None specified
Cost Analysis: Unknown

Table VI-2
Monitoring Requirements for Flares at Refineries in the State of New Mexico

Primary Source Category: Refinery/New Mexico
Source Type: Flare
Emission Measurement/Quantification System: Emissions derived by calculation from data generated by recordkeeping and reporting requirements.
Averaging Times: Not Applicable
Consideration of Batch, Seasonal, and Cyclical Operations: Supplemental heat to be provided in proportion to the quantity of acid gas being flared.
Calculations Used to Determine Quarterly and Annual Mass Emissions: Acid gas flow and concentration.
Procedures for Addressing Missing and Invalid Data: Not Applicable
Recordkeeping and Reporting Requirements: Records of: All periods of operation during which the flare pilot flame is absent in flare and the steps taken to re-ignite the pilot; Repairs, maintenance, and calibration of the acid gas flowmeter for flare; Repairs, maintenance.
Initial Performance Testing: Flares used to comply with the NSPS Subpart GGG requirements for VOC shall be tested in accordance with the requirements contained in 40 CFR 60, Subpart A, General Provisions, paragraph 60.8 (performance tests) and 60.18 (general control device requirements). No independent tests for SO_2 emissions.
Periodic Calibration: The H_2S monitor shall be operated, maintained, and certified in accordance with 60.105; The H_2S monitors shall be re-certified no later than every 3 years from the date of the original and subsequent certifications.
Audits: The H_2S monitor shall be operated, maintained, and certified in accordance with 60.105; The H_2S monitors shall be re-certified no later than 3 years, from the date of the original and subsequent certifications.
Other Appropriate Quality Control and Quality Assurance Measures: Flare shall be equipped with a flare tip or burners to supply supplemental fuel gas to provide enough supplemental heat. An alarm system in good working order shall be connected to a flare that will signal non-combustion of the gas. In accordance with 60.104, the fuel gas to be combusted in affected heaters and affected flare pilots shall be sweetened refinery fuel gas with a maximum H_2S concentration of 0.1 grain/dscf. In accordance with 60.105, the H_2S concentration of the refinery fuel gas supplied to the affected heaters or flare pilots shall be monitored by a continuously recording H_2S monitor. An alarm in good working order to signal non-combustion of the gas shall be installed.
Cost Analysis: Unknown.

Table VI-3
Monitoring Requirements for Flares at Natural Gas Processing Plants in the State of New Mexico

Primary Source Category: Natural Gas Processing Plants/New Mexico
Source Type: Flare
Emission Measurement/Quantification System: An analyzer system shall be installed to automatically measure and record on an ongoing basis: (1) the flow rate of the inlet gas to the plant, (2) the H_2S concentration of the inlet gas to the plant, (3) the flow rate of the acid gas to the flare, and (4) the H_2S concentration of the acid gas to the flare.
Averaging Times: The H_2S concentration of the <u>inlet gas</u> shall be measured and recorded at least once every three hours. The flow rates shall be measured and recorded at least once per hour. The H_2S concentration of the <u>acid gas</u> shall be measured and recorded at least twice per day.
Consideration of Batch, Seasonal, and Cyclical Operations: None.
Calculations Used to Determine Quarterly and Annual Mass Emissions: Daily H_2S volume * H_2S concentration (PPMV) * H_2S (MW) * 64/32 / E^6 * 385 (F factor) * 24 hrs/day.
Procedures for Addressing Missing and Invalid Data: None
Recordkeeping and Reporting Requirements: Daily records of the following are required: (1) the flow of gas entering the plant (MMSCF), (2) the average daily H_2S concentration of the inlet gas (ppmv), (3) the amount of sulfur (short tons) inlet to the plant using the results of 1 and 2, above, (4) the flow of acid gas sent to the flare (MMSCF), (5) the H_2S concentration of the acid gas sent to flare (ppmv), (6) the amount of sulfur (short tons) sent to the flare using the results of 4 and 5, above, (7) the percent of the inlet sulfur that was flared using the results of (3) and (6), above.
Initial Performance Testing: For sources subject to NSPS, testing shall be required in accordance with the requirements contained in 40 CFR 60, Subpart A, General Provisions, paragraph 60.8 (performance tests) and 60.18 (General Control Device Requirements).
Periodic Calibration: A standard operating procedure (SOP) for the flow and concentration calibration procedure for the H_2S concentration instruments shall be developed and approved. Proper operation of the alarm system or the spark igniter is to be checked once in January and once in July of each year.
Audits: The H_2S concentration certification tests shall be conducted in accordance with EPA Performance Specification 7 (PS-7) in 40 CFR Appendix B. However, PS-7 will need to be modified to accommodate the high H_2S concentrations that will be encountered in the acid gas. The proposed modifications to PS-7 shall be explained in the test protocol.
Other Appropriate Quality Control and Quality Assurance Measures: The acid gas flare shall be equipped with either (1) a well maintained alarm system that signals non-combustion of the gas, or (2) an automatic spark igniter that sends an ignition spark to the flare pilot.
Cost Analysis: Unknown

CHAPTER VII
LIME KILNS

In the western States, there are lime kilns at lime manufacturing plants and at pulp and paper mills. There are two primary types of lime kilns, rotary kiln and vertical kilns. Other types include rotary hearth and fluidized bed kilns. Rotary kilns, account for about 90 percent of all U.S. lime production and can burn coal, oil, and natural gas. The other types of kilns cannot burn coal as readily, therefore, these kilns are less common. The WRAP inventory information indicates that no vertical kilns are included in units addressed in the floor allocations for the trading program (based on a review of source classification codes).

SO_2 emissions are influenced by several factors, including the fuel sulfur content, the sulfur content and the stone feed form (pyrite or gypsum), the quality of lime being produced, and the type of kiln. The primary source of SO_2 emissions is from the combustion of fossil fuel to heat the kiln. The vast majority of the fuel sulfur is not emitted because of reactions with calcium oxides in the kiln. SO_2 emissions may be also be reduced if the pollution equipment uses a wet control process for particulates or if it brings calcium oxides and SO_2 into intimate contact. Since SO_2 control is inherent to the process, additional controls are not typically applied to lime plants.

NSPS for Kraft Pulp Mills are specified in 40 CFR 60 Subpart BB. This standard requires CEMS for total reduced sulfur (TRS) emissions (on a dry basis) and O_2 (% by volume on a dry basis) for affected lime kilns at kraft pulp mills. If the source uses a SO_2 scrubber control device, the source can monitor for continuous measurement of the pressure loss across the control device and scrubbing liquid supply pressure rather than employ a CEMS. The same record keeping requirements apply. Monitoring requirements are summarized in Table VII-1.

Lime kilns are located in the States of Arizona, California, Nevada, and Utah. There are seven pulp and paper lime kilns located in the State of Oregon. Summaries of SO_2 monitoring requirements were obtained from Nevada and Oregon and are given in Table VII-2 and Table VII-3, respectively. Nevada requires analysis of the fuel sulfur content. In addition it requires monitoring daily production. SO_2 emissions are calculated using a permit-specific emissions factor. Stack emission testing is required once every 5 years. Best SO_2 monitoring practices for pulp and paper lime kilns in the State of Oregon require a CEMS for TRS measured as H_2S. A stack test is required once every 4 years. The SCAQMD has one lime kiln. Lime kilns must follow the general district SO_2 monitoring rules, which require either SO_2 CEMS and flow monitoring, or fuel gas continuous monitoring (sulfur content and fuel flow). It is not known what type of monitoring is being performed at the lime kiln in SCAQMD.

Table VII-1
NSPS Monitoring Requirements for Lime Kilns at Kraft Pulp and Paper Mills

Primary Source Category: Pulp and Paper
Source Type: Lime Kiln
Emission Measurement/Quantification System: CEMS for TRS emissions (dry basis) and O_2 (% by volume on a dry basis). CEMS located downstream of the control device(s). Span value: 30ppm TRS and 25% O_2. For any lime kiln or smelt dissolving tank using a scrubber emission control device: 1) monitor for continuous measurement of the pressure loss across the control device 2) monitor for continuous measurement of the scrubbing liquid supply pressure to control device
Averaging Times: For CEMS: 1-hour averages of CEMS TRS (corrected to 10% O_2) and O_2 computed from four or more data points equally spaced over each 1-hour period. 12-hour average TRS and O_2 based on arithmetic mean of 12 contiguous 1-hour averages from CEMS For pressure monitors: Record pressure measurements once per shift
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: None specified
Procedures for Addressing Missing and Invalid Data: None specified
Recordkeeping and Reporting Requirements: Requires semiannual report including periods of excess emissions. The procedures under §60.13 shall be followed for evaluation and operation of the CEMS.
Initial Performance Testing: The pressure drop monitor is to be certified by the manufacturer to be accurate to within a gage pressure of ±500 pascals (ca. ±2 inches water gage pressure). The supply liquid pressure monitor is to be certified by the manufacturer to be accurate within ±15 percent of design scrubbing liquid supply pressure. The procedures under §60.13 shall be followed for installation.
Periodic Calibration: The procedures under §60.13 shall be followed for evaluation and operation of the CEMS. Performance Specifications 1, 3, and 5 of Appendix B using Method 16 for TRS Method 3B for O_2. Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of Appendix F.
Audits: For CEMS: in accordance with Appendix F
Other Appropriate Quality Control and Quality Assurance Measures: For CEMS: in accordance with Appendix F
Cost Analysis: Unknown

Table VII-2
Monitoring Requirements for Lime Kilns in the State of Nevada

Name: Graymont Western (formerly Continental Lime)
Primary Source Category: Lime Plants
Source Type: Lime Kiln (specifically, 3 lime kilns and associated equipment)
Emission Measurement/Quantification System: Current permit limits coal sulfur content and throughput. Monitoring requires daily coal sulfur analyses (from a composite of samples taken once per shift), daily production records, annual emission reporting, and stack emission testing once every 5 years.
Averaging Times: All emission limits are based on hourly averages as well as annual averages.
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: Annual production * Emission Factor. The emission factor is generally provided by the Agency and is obtained from the permit limits (emissions limit ÷ permitted production rate).
Procedures for Addressing Missing and Invalid Data: None
Recordkeeping and Reporting Requirements: See above
Initial Performance Testing: Currently, a performance test is required within 180 days of permit issuance and once every five years thereafter.
Periodic Calibration: None, beyond those typically performed during the performance testing.
Audits: Typically, once per year by Agency compliance staff, or more frequently, if necessary.
Other Appropriate Quality Control and Quality Assurance Measures: None
Cost Analysis: None Provided

Table VII-3
Monitoring Requirements for Pulp & Paper Lime Kilns in the State of Oregon (excluding Lane County)

Primary Source Category: Unbleached Kraft Pulp Linerboard and Corrugating Medium Mill
Source Type: Lime Kilns
Emission Measurement/Quantification System: CEMS for TRS (as H_2S)
Averaging Times: TRS: Daily arithmetic averages calculated from 1-hour arithmetic averages
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: TRS: Calculate emissions of total reduced sulfur (TRS/ton equivalent air dried pulp) by: -daily average concentration -flow rate estimated from source tests & firing rate correlation -equivalent ADTP production
Procedures for Addressing Missing and Invalid Data: None, 75% data recovery on a 1-hour period and 90% data recovery for a 1-hour period required for a CMS data average to be accepted (ODEQ Continuous Monitoring Manual).
Recordkeeping and Reporting Requirements: The permittee shall report the following information within 30 days of the end of each calendar month: -Daily average concentration of TRS gases -Daily average emissions of TRS gases as lbs/equivalent tons of pulp processed
Initial Performance Testing: No performance testing requirements of emission unit within current permit that exceeds the CEMS auditing procedures (RATA)
Periodic Calibration: Daily Calibrations
Audits: Quarterly audits, either CGA or RAA. Once every four quarters a RATA is required
Other Appropriate Quality Control and Quality Assurance Measures: Mandatory submittal and periodic review of CEM quality assurance plan and standard operating procedures manual.
Cost Analysis: Unknown

CHAPTER VIII
CEMENT KILNS

Cement kilns generate SO_2 emissions from two processes; 1) the combustion of fuel which contains sulfur, and 2) heating of the feedstock, generally pyrite, which also contains sulfur. SO_2 emissions vary by kiln type, generally based on how effectively the kiln type mixes the SO_2 containing gases with the alkaline calcium compounds. Emissions from kilns also vary according to the sulfur content of the feedstock. Changes in feedstock can cause a change in emissions up to a factor of 100. According to EPA AP-42 emission factors, emissions from cement kilns can vary by as much as a factor of 20.

There are cement kilns in Arizona, Colorado, Idaho, Nevada, New Mexico, Utah and Wyoming. Monitoring requirements for SO_2 emissions from cement kilns vary among States and may be kiln-specific. Information about existing SO_2 monitoring requirements was obtained from Nevada, Colorado and Oregon. These requirements are summarized in Table VIII-1, Table VIII-2, and Table VIII-3, respectively.

Nevada and Oregon require analysis of the sulfur content of the fuel and feedstock and monitoring of total annual throughput and annual fuel usage. SO_2 emissions are then estimated from published emission factors. Nevada and Oregon also require periodic stack testing to ensure compliance. Colorado requires a CEMS for SO_2 monitoring of cement kilns. No information on stack testing requirements in Colorado was available. One kiln in Nevada has a positive pressure baghouse (open baghouse), therefore, monitoring of stack emissions is not required at this source.

The SCAQMD reported via a teleconference that it has two cement kilns operating in the district. One cement kiln uses a SO_2 CEMS with a stack flow monitor. The other cement kiln, which uses a positive pressure baghouse for particulate control, measures SO_2 (and NO_x) with CEMS upstream of the baghouse. Plant SO_2 emission concentrations are low, so measuring before the baghouse does not have a significant impact on emission accounting. The heavy particulate loading upstream of the baghouse precludes the use of a standard flow monitoring technique. Therefore, stack flow is measured using a correlation with fan amperage measurements. This correlation method is subject to relative accuracy testing using Reference Method 2.

Table VIII-1
Monitoring Requirements for Cement Kilns in the State of Nevada

Name: Nevada Cement Company
Primary Source Category: Cement Plants
Source Type: Cement Kilns (specifically, 2 cement kilns and associated equipment). One kiln is controlled by a positive pressure baghouse (non-testable), the other kiln is testable.
Emission Measurement/Quantification System: Current permit limits coal sulfur content and throughput. Monitoring for total annual throughput and annual fuel is required for Kiln #1. Monitoring for Kiln #2 requires monthly coal sulfur analyses (from a composite of samples representing each delivery received in the month), and annual production records. Annual emission reporting is required for both units, and stack emission testing once per year for Kiln #2 only.
Averaging Times: All emission limits are based on hourly averages as well as annual averages except for NO_x, which has only an annual average.
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: Annual production * Emission Factor. The emission factor is generally provided by the Agency and is obtained from the permit limits (emissions limit ÷ permitted production rate). A source test result can also be used to replace the provided emission factor.
Procedures for Addressing Missing and Invalid Data: None
Recordkeeping and Reporting Requirements: See above
Initial Performance Testing: Currently, a performance test is required within once per year.
Periodic Calibration: None, beyond those typically performed during the performance testing.
Audits: Typically, once per year by Agency compliance staff, or more frequently if necessary.
Other Appropriate Quality Control and Quality Assurance Measures: None
Cost Analysis: None Provided

Table VIII-2
Monitoring Requirements for Cement Kilns in the State of Colorado

Facility Name: Holcim, Inc. Florence Plant (Colorado)
Primary Source Category: Portland Cement Manufacturing
Source Type: Kiln/Precaliner
Emission Measurement/Quantification System: Continuous Emission Monitoring System for SO_2 and Flow
Averaging Times: Annual
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: Pounds per hour (lbs/hr) values are totaled to arrive at the annual mass emissions.
Procedure for Addressing Missing and Invalid Data: Not sure
Recordkeeping and Reporting Requirements: Keep emission data onsite for review.
Initial Performance Test: Not sure
Periodic Calibration: Daily calibrations
Audits: Cylinder gas audits quarterly
Other QA/QC Activities: Annual RATAs

Table VIII-3
Monitoring Requirements for Cement Kilns in the State of Oregon (excluding Lane County)

Primary Source Category: Portland Cement Manufacturing
Source Type: Kiln/Roller Mill System
Emission Measurement/Quantification System: Monitoring the sulfur content of each shipment of fuel received
Averaging Times: Not Applicable
Consideration of Batch, Seasonal, and Cyclical Operations: No
Calculations Used to Determine Quarterly and Annual Mass Emissions: Mass emissions determinations on a 12 consecutive calendar month basis to determine compliance with the plant site emission limit (PSEL) is performed as follows: $E_i = \sum \frac{(Peu\ x\ EFeu)}{K_1}$ $E_{12m} = (E_i + E_{ii} + E_{iii} + etc.)$ $E_{12m} = (E_i + E_{ii} + E_{iii} + etc.)$ Peu = tons of clinker per month EFeu = 0.100 lb SO_2/ton clinker K1 = 2000 lbs/ton
Procedures for Addressing Missing and Invalid Data: Not Applicable
Recordkeeping and Reporting Requirements: The permittee must maintain records of the sulfur content of each shipment of fuel received. The permittee shall maintain records of daily clinker production and kiln feed rates. Semi-annual reporting of compliance certification.
Initial Performance Testing: The permittee must determine compliance with the sulfur dioxide standards by conducting a source test once each permit term.
Periodic Calibration: Not Applicable
Audits: Audit records during inspection and review source test report.
Other Appropriate Quality Control and Quality Assurance Measures: Not Applicable
Cost Analysis: Costs for source testing and recordkeeping labor-hours unknown

CHAPTER IX
ALUMINUM SMELTERS - POTLINES

The primary source of SO_2 emissions in aluminum production is the sulfur in the petroleum coke and the coal tar pitch binder used to produce the anodes. In the prebake process, the combustion fuel to bake the anodes may also be a significant SO_2 emission source. As the coke is processed or consumed in the reduction cell, SO_2 is released. The majority of SO_2 emissions are collected by the pot hood exhaust system. SO_2 emissions are generally controlled by limiting the sulfur content in the coke and pitch used in the anodes. SO_2 can also be controlled by a wet scrubber.

The NSPS for primary aluminum plants limits fluoride emissions, but does not address SO_2 emissions. Washington is the only State that has established an SO_2 emission limit specifically for primary aluminum plants. Washington, however, is outside the trading region. Washington's rule limits the maximum allowable total SO_2 emissions from all sources within the plant to 60 lbs per ton of aluminum produced on a monthly basis. In addition, it limits SO_2 stack emissions to 1,000 ppm.

There are 2 primary aluminum plants located in Oregon, Reynolds Metal and Northwest Aluminum. Note that the Reynolds Metal facility is permanently shut down and the primary smelting operations at the Northwest Aluminum facility are currently shut down. Monitoring requirements for aluminum smelters in the State of Oregon are listed in Table IX-1. Since there are a limited number of sources in the trading region, Pechan obtained monitoring requirements for the State of Washington as well. Washington State has seven aluminum smelters. Pechan reviewed two air permits for primary aluminum plants located in the State of Washington: Vanalco, Inc. and Kaiser Aluminum & Chemical Corp. The monitoring requirements for these facilities are summarized in Table IX-2.

The State of Oregon requires periodic stack testing of SO_2 in order to monitor emissions from aluminum smelters. In the State of Washington, SO_2 emissions are required to be monitored using either a mass balance approach, which requires sampling of the sulfur content of the petroleum coke and pitch, or periodic stack testing. Note that the State of Washington calculated SO_2 emissions for the Kaiser and Vanalco plants under normal operating conditions (normal air flow rate and highest aluminum production rate). These estimates were well below the State's 1,000 ppm limit, with the possible exception of an upset condition. Therefore, the plants are exempt from monitoring for the 1,000 ppm standard.

A wet scrubber is the floor SO_2 control technology assumed for aluminum smelters based on Northwest Aluminum having this SO_2 control in-place at its Oregon plant. A possible monitoring requirement for aluminum smelters, which have or install a wet scrubber, is to monitor the pressure drop across the scrubber and the scrubbing liquid pressure. This approach is an option under the NSPS for lime kilns at kraft pulp and paper mills and under the Compliance Assurance Monitoring (CAM) Rule for Title V sources. The pressure drop and scrubbing liquid pressure monitors the performance of the scrubber and not SO_2 emissions. Therefore, this approach does not necessarily indicate compliance with regulations. Table IX-3 presents costs for monitoring the pressure drop across a wet scrubber (assumed cost year is 1999).

Table IX-1
Aluminum Smelter Monitoring Requirements in the State of Oregon (excluding Lane County)

Primary Source Category: Primary Aluminum Production
Source Type: Potlines
Emission Measurement/Quantification System: Three test runs per semi-annual period by EPA Methods 6, 6A, or 6B.
Averaging Times: Not Applicable
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: The permittee shall perform source testing to monitor compliance with the potlines contribution to SO_2 short term and annual plant site emission limits.
Procedures for Addressing Missing and Invalid Data: Enforcement actions may be taken if testing is not performed as required.
Recordkeeping and Reporting Requirements: The permittee shall report the SO_2 emissions expressed in ppm and lbs/TAP within 30 days of the end of each calendar quarter.
Initial Performance Testing: Performance testing required semi-annually
Periodic Calibration: Not Applicable
Audits: Audit records during inspection and review of source test report.
Other Appropriate Quality Control and Quality Assurance Measures: None
Cost Analysis: Unknown

Table IX-2
Aluminum Smelter Monitoring Requirements in the State of Washington

Primary Source Category: Primary Aluminum Production
Source Type: Potlines
Emission Measurement/Quantification System: Requires the following; 1) analyze sulfur content of each load or batch of petroleum coke and pitch using ASTM D4239, and 2) measure aluminum production daily, or source testing. Note that sources are exempt from monitoring for 1,000 ppm SO_2 standard since they can demonstrate, using a worse-than-worst-case analysis, that the source is incapable of violating the standard, with the possible exception of an extreme upset condition.
Averaging Times: Monthly
Consideration of Batch, Seasonal, and Cyclical Operations: Sample each batch of coke and pitch.
Calculations Used to Determine Quarterly and Annual Mass Emissions: Calculate SO_2 emissions from mass balance assuming all sulfur converts to SO_2. SO_2/ton Al = [∑(C x SC)+(∑(P x SP)+∑(O x SO)] x 40 / Al where C, P, and O are the coke, pitch, and fuel oil usage during the month from each shipment, in tons; SC, SP, and SO are the % sulfur concentration of each shipment of coke, pitch or fuel oil, respectively; and Al is the aluminum production for the month. The factor of 40 derives from converting tons of raw materials to pounds (2,000 lbs/ton), converting the percentage of sulfur in raw materials to a decimal fraction (100), and converting the weight of sulfur to the weight of SO_2 (1 lb sulfur equals 2 lbs SO_2).
Procedures for Addressing Missing and Invalid Data: None Specified
Recordkeeping and Reporting Requirements: Submit monthly report of SO_2 emissions (lbs SO_2/ton Al) including records of raw materials usage, representative raw materials sample analysis and aluminum production rate.
Initial Performance Testing: Upon request, source must conduct SO_2 emissions testing using EPA Test Method 6, 6A, 6B, 6C or 8 from 40 CFR Part 60 Appendix A.
Periodic Calibration: None
Audits: None Specified
Other Appropriate Quality Control and Quality Assurance Measures: None Specified
Cost Analysis: Unknown

Table IX-3
Costs for Monitoring Pressure Drop Across Wet Scrubber

Item	Total Cost, $
Capital and other initial costs	
Planning[a]	4,890
Equipment selection[b]	0
Support facilities[c]	2,000
Purchased equipment cost[d]	3,260
Install and check DAS[e]	5,680
Data collection text[f]	16,140
Total Capital Investment (TCI)	31,970
Annual Costs, $/yr	
Operation and maintenance[g]	900
Annual RATA[h]	10,930
Recordkeeping and reporting[i]	2,020
Property taxes, insurance, and administrative[g]	1,280
Capital recovery[h]	3,020
Total Annual Cost, $/yr	26,650

[a]Based on $4,250 labor to review regulations, define monitoring requirements and develop CAM plan plus $640 in supplies.
[b]Cost of selecting PC-based data acquisitions system included in planning costs.
[c]Cost of installing sampling ports in stack.
[d]Cost based on Pentium class PC, monitor, printer, and operating software.
[e]PC installation and interconnection for sensor signals, equipment calibrations and start-up services.
[f]Cost for data collection testing is based on the cost for initial RATA testing on a CEM.
[g]Based on 10% of purchased equipment cost + 10% of installation labor cost.
[h]Cost for data collection testing is based on the cost for annual RATA testing on a CEM.
[i]5 min. per shift 3 shifts per day x (365 days/yr) @ $17.50/hr for operators.
[j]Add 2.5% of operator time for engineerís review @ $30/hr, 2.5% of operator time for managerís review @ $50/hr, 10% of operator time for clerical support @ $10/hr and $100 for supplies.
[k]QA planning, training, and equipment inventory estimated to be 50% of CEM cost.
[l]Based on 4% of TCI, 20 year life and 7% interest.

SOURCE: EPA, 2002.

CHAPTER X
GLASS MANUFACTURING

The major source of SO_2 emissions in the glass industry is the glass melting furnace. Furnace emissions appear to be attributable to both the manufacturing process and the fuel burned. Fuel-derived SO_2 emissions are lower from natural gas-fired furnaces than from oil-fired furnaces, unless the oil has been desulfurized.

SO_2 monitoring requirements were evaluated for glass manufacturing plants in Colorado, Oregon, and the SCAQMD. The plants in Colorado and Oregon emitted all SO_2 via a stack. The summaries of these monitoring requirements are provided in Table X-1, Table X-2, and Table X-3 respectively. Colorado requires continuous monitoring systems for SO_2 and monitoring of fuel consumption, while Oregon estimates SO_2 emissions from monthly production records for tons of glass melted, and natural gas and fuel oil fuel usage estimates from meter/gauge readings. SO_2 emissions are then calculated using emission factors.

The SCAQMD requires the use of CEMS at the glass plant(s). There are some flow monitoring issues at these plants because oxy-fuel systems are being adopted (using oxygen rather than air). Oxygen use reduces the overall flow as there is reduced oxidizer volume. In these cases, they cannot use an alternate method such as measurement of the fuel burned and use of an f-factor to determine stack flow. In-stack flow meters must be used or an alternative method for low flow rates such as the use a tracer gas (e.g., helium).

Table X-1
Monitoring Requirements for Glass Manufacturing in the State of Colorado

Name: Rocky Mountain Bottle Company
Primary Source Category: Glass Manufacturing
Source Type: Glass Melting Furnaces and Bottle Making Machines
Emission Measurement/Quantification System: <u>Glass Melting Furnaces:</u> Current permit limits SO_2 emissions to 82.65 lb/hr and 362 tpy. CEMS must be installed, calibrated, maintained and operated for the measurement of SO_2 emissions discharged from the combined stack. The hourly emission limits are based on an average of emissions for the hours of operation during each 28 day period of operation. <u>Bottle Making Machines:</u> Current permit limits SO_2 emissions and oil consumption. SO_2 emissions are calculated by the end of each subsequent 28 day period. The bottle making machines are a minor SO_2 source (limited to 6.8 tpy).
Averaging Times: Emission limits are based on hourly averages as well as annual averages.
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: <u>Bottle Making Machines:</u> Oil consumption/period * Emission Factor Emission Factor = 0.105 ton of SO_2 /ton of oil consumed
Procedures for Addressing Missing and Invalid Data: None
Recordkeeping and Reporting Requirements: Submission of compliance certifications including emission limitations are required not less than annually. Monitoring deviation reports are due at least every six months. A 13-period rolling total of emissions must be maintained for demonstration of compliance with annual emissions. Reports must be retained for at least 5 years.
Initial Performance Testing: None
Periodic Calibration: None.
Audits: Once per year by Agency compliance staff, or more frequently, if necessary
Other Appropriate Quality Control and Quality Assurance Measures: None
Cost Analysis: None Provided

Table X-2
Monitoring Requirements for Glass Manufacturing in the State of Oregon

Name: Owens-Brockway Glass Container, Inc.
Primary Source Category: Glass Manufacturing
Source Types: Glass Melting Furnaces and Boilers emit SO_2
Emission Measurement/Quantification System: Current permit limits SO_2 emissions to 313 tpy. <u>Glass melting furnaces:</u> Record the tons of glass melted per month using production records. Measure natural gas and fuel oil volume burned per month by using fuel usage meter/gauge readings. Current permit limits sulfur content of distillate oil. Sulfur content is monitored by obtaining an analysis certificate from the vendor of each batch or by analyzing representative samples from each batch of fuel received. Sulfur content is analyzed by using Methods ASTM D129-64, D1552-83, or D4057-81 or an equivalent method. <u>Boilers:</u> Measure natural gas and fuel oil volume burned per month by using fuel usage meter/gauge readings. Current permit limits distillate oil sulfur content. Sulfur content is monitored by obtaining an analysis certificate from the vendor of each batch or by analyzing representative samples from each batch of fuel received. Sulfur content is analyzed by using Methods ASTM D129-64, D1552-83, or D4057-81 or an equivalent method.
Averaging Times: 12-month rolling average.
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Monthly and Annual Emissions: <u>Monthly Emissions:</u> $E_{MO,i} = P_i EF_{i,j} K$ <u>Yearly Emissions:</u> $E_{Annual} = \sum_{\text{Past 12- month}} E_{MO,i}$ Where : $E_{MO,i}$ = monthly pollutant emissions from individual device Pi = operating parameter EFi,j= emission factor based on AP-42 and testing, depends on emission unit, given in lbs/lb of SO_2 used, lbs/1000 gal, or lbs/ 10^6 ft^3. K= conversion factor (1 ton/2,000 lbs or 2,000) The emission factors for the furnaces and boilers are: EU4 - Distillate Oil 142 (%S) AP-42 GM1 - Glass Melted 1.5 lbs/ton glass Testing GM4 - Glass Melted 0.70 lbs/ton glass Testing EU7 - Natural Gas 2.6 lbs/ 10^6 ft^3 AP-42 EU7 - Distillate Oil 142 (%S) AP-42 The emission factor for the glass melting furnaces must be verified once every five years by using EPA Method 6, 6c.
Procedures for Addressing Missing and Invalid Data: None
Recordkeeping and Reporting Requirements: Monthly and annual records of fuel oil and natural gas consumption must be maintained. Semi-annual and annual monitoring reports are required. Monitoring data and support information must be kept for at least 5 years.
Initial Performance Testing: None
Periodic Calibration: None
Audits: Typically, once per year by Agency compliance staff, or more frequently if necessary.
Other Appropriate Quality Control and Quality Assurance Measures: None
Cost Analysis: None Provided

Table X-3
Monitoring Requirements for Glass Manufacturing in the SCAQMD, California

Primary Source Category: Glass Manufacturing Plants
Source Type: Boilers/ Furnaces
Emission Measurement/Quantification System: Must install, calibrate, maintain, and operate an approved CEMS or Alternative Monitoring System (AMS). CEMS/AMS must measure: a. Sulfur oxide concentrations discharged from stack, b. Fuel gas flow rate and sulfur content, if the CEMS uses these to determine SO_x emissions. c. Stack gas volumetric flow rate using one of the following methods; 1. An in-stack flow meter, 2. An approved alternate method such as measurement of the fuel burned and use of an f-factor to determine stack flow. The fuel measurements must meet the same relative accuracy as the flow monitor, and are tested against reference method 2. 3. Glass furnaces using oxygen-fuel systems operate at low flow rates due to the use of oxygen rather than air as the oxidizer. These systems require in-stack flow meters or use of a tracer gas to determine a dilution ratio and stack flow. 4. Oxygen concentrations, at sulfur oxide monitoring location if required for stack gas flow rate.
Averaging Times: 1-hour average equally computed based on four valid 15-minute average emission data points equally spaced over each 1-hour period. (Only 2 required during CEMS maintenance activities)
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Monthly and Annual Emissions: Sulfur oxide mass emissions in units of lb/hour: $e_i = a_i \times c_i \times 1.662 \times 10^{-7}$ where: e_i = Mass emissions of sulfur oxides (lb/hr), a_i = Stack gas concentration of sulfur oxide (ppmv), and c_i = Stack gas volumetric flow rate (scfh). The daily emissions of sulfur oxides for each affected SO_x source: $G = \sum_{k=1}^{n} E_k + \sum_{m=1}^{p} E_m$ where: G = Daily emissions of sulfur oxide (lb/day), E_k = Hourly average emission rate using CEMS (lb/hr) E_m = Hourly average emission rate of sulfur oxides using substitute data (lb/hr), n = Number of hours of valid data from CEMS coinciding with the operating hours p = Number of hours using substitute data when the source is operating; and m = Number of operating hours of the source during the day.

Procedures for Addressing Missing and Invalid Data: Emission rate data may be obtained using District Methods 6.1 or 100.1 (for SO_x) in conjunction with District Methods 1.1, 2.1, 3.1, and 4.1 or by using District Methods 6.1 or 100.1 in conjunction with District Method 3.1 and EPA Method 19. Emission rate data may also be obtained using District Methods 307-91 or ASTM Method D1072-90, Standard Test for Total Sulfur in Fuel Gases (for sulfur content in the fuel gas) in conjunction with the fuel gas flow rate. May use the procedure in 40 CFR Part 75 Subpart D if the relative accuracy of the pollutant analyzer and flow measurement system during the last CEMS certification test and/or RATA are both less than 10%. Calculate on a daily basis the percent data availability of analyzer then substitute data calculated as: a. if availability is >= 95% and missing data is: < 24 hours: 1N Procedure in Attachment A or E(1)(b)(ii), or > 24 hours: max hourly concentration recorded for previous 30 days. b. if availability is >= 90% and missing data is: < 3 hours: average of concentration for the hour before and after missing data period, > 3 hours: max hourly concentration recorded for previous 30 days, or > 24 hours: max concentration recorded for previous 365 days c. if availability is > 90%: highest hourly concentration recorded during the service of the CEMS.
Recordkeeping and Reporting Requirements: 1. Total daily SO_x mass emissions from each source, 2. Daily status codes, 3. Daily electronic transmittal of RTU data, 4. Monthly submittal of daily records of SO_x emission rates per thousand barrels of feed, 5. Monthly aggregated SO_x emissions, 6. Semi-annual and CEMS certification tests 7. Must submit a CEMS plan for approval CEMS data shall be recorded by: 1) RTU and 2) strip chart or alternative electronic recorder. The strip chart recorder or alternative shall receive data independent of the RTU and serve as an independent tool for verifying data. Must measure and record 1) variables necessary for the alternate gas volumetric flow rate method, 2) measurements in Table 2-A and 3) other measured data to support calculations. Recorded data shall be readily accessible upon request. Must maintain records of measurements, tests, calibration audits and QA data for 3 years. Keep a written record of QA and audit procedures.
Initial Performance Testing: Same requirements as audits
Periodic Calibration: CEMS design shall allow determination of calibration drift. Requires zero and span calibration checks, and zero and span adjustments. Perform any calibration error test procedures specific to the CEMS. Attachment C Quality Assurance And Quality Control Procedures: 1. Test, record, and compute the calibration error of each monitor at least once per operating day. Perform the daily calibration error test according to the procedure in Chapter 2, Subdivision B, Paragraph 1, Subparagraph a, Clause ii of this Attachment. 2. Test, compute, and record the calibration error of each stack flow monitor at least once per 14 calendar days. Perform daily flow monitor interference checks. All transducers and transmitters installed on stack flow monitors must be calibrated every two operating calendar quarters.

Audits: Requires semi-annual CEMS certification test Meet specifications in 40 CFR Part 60, Appendix B, Performance Specification 2, Section 8 and Appendix A Attachment B Bias Test of this rule. Minimum of nine sets of tests conducted. Specifies alternate procedures. 1. Monitors and Analyzers: relative accuracy of >= 20% of the mean value of the reference method test data. 2. Volumetric flow measurement system: relative accuracy of >= 15% of the mean value of the reference method test data. Must perform study to determine the acceptability of the potential flow monitor location and to determine the number and location of flow sampling points. 3. Must demonstrate the absence of stratification (difference between highest and lowest concentration divided by average concentration is >10%.
Other Appropriate Quality Control and Quality Assurance Measures: None
Cost Analysis: None Provided

CHAPTER XI
METALLURGIC COKE PRODUCTION

Metallurgical coke is derived from coal and used in iron and steel industry processes. Coke is manufactured by pyrolysis, the heating of coal in the absence of air. In this process, high grade, bituminous coal is heated in an enclosed chamber to approximately 1050°C, which removes all volatile elements of the coal. The resulting product is a solid material consisting of elemental carbon and any minerals that were not volatilized in the heating process.

There are limited coke production operations in the WRAP Region. Protocols for this industry are based on the rotary calciner used for coke production at P4 Production in Rock Springs, Wyoming and facilities operating in the South Coast of California. Table XI-1 summarizes the existing SO_2 emission monitoring requirements for P4 Production. In short, no SO_2 emission monitoring is required for this facility. Annual SO_2 emissions are computed using the stack test-based SO_2 emission factor and operating hours/production rate estimates.

There is at least one coke calciner included in the South Coast RECLAIM program, and the CEMS and flow monitoring requirements are no different from those applied under SCAQMD Rule 2011 for other source types, so the SO_2 emission monitoring protocol is not repeated in this chapter.

Table XI-1
Monitoring Requirements for Coke Production in the State of Wyoming

Name: P4 Production - Rock Springs Coking Plant
Primary Source Category: Coke Manufacturing
Source Type: Rotary Coker. This plant uses petroleum coke blended with coal as a feedstock. SO_2 emissions result from the sulfur in these fuels.
Emission Measurement/Quantification System: No SO_2 emissions monitoring is required for this facility. SO_2 emission factors are based on stack tests. The last stack test on the main coker stack was performed just prior to issuance of the Title V permit (prior to 1999). All SO_2 emissions are via the stack.
Averaging Times: Emission limits are annual totals.
Consideration of Batch, Seasonal, and Cyclical Operations: None
Calculations Used to Determine Quarterly and Annual Mass Emissions: Annual emissions are estimated using the stack test-based SO_2 emission factor and operating hours. The annual throughput is estimated using the average feed rate for the year (in tons per hour). The tested feed rate is pro rated for the year's production.
Procedures for Addressing Missing and Invalid Data: None
Recordkeeping and Reporting Requirements: Emission fees are based on annual emission estimates submitted to the State of Wyoming.
Initial Performance Testing: None
Periodic Calibration: None.
Audits:
Other Appropriate Quality Control and Quality Assurance Measures: None
Cost Analysis: None Provided

CHAPTER XII
SULFURIC ACID PRODUCTION

Emission monitoring protocols for sulfuric acid plants are addressed in Chapter II - Copper Smelters. See Table II-2 for a summary of the SO_2 monitoring requirements for the acid plant at Kennecott Copper in Utah and Table II-4 for the monitoring requirements for acid plant tail gas at copper smelters in Arizona. Because SO_2 CEMS and flow monitoring are required for the Kennecott unit, these are considered the best monitoring practices for H_2SO_4 production.

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